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Directive 017

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Measurement Requirements for Oil and Gas Operations

The Energy Resources Conservation Board (ERCB/Board) has approved this directive on September 4, 2012.

<original signed by>

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Chairman

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Introduction

Purpose

Directive 017 consolidates, clarifies, and updates Energy Resources Conservation Board (ERCB) requirements for measurement points used for ERCB accounting and reporting purposes, as well as those measurement points required for upstream petroleum facilities and some downstream pipeline operations under existing regulations. The term "measurement" as used in this document means "measurement, accounting, and reporting." While measurement is the determination of a volume, accounting and reporting are integral components of measurement in that after a fluid volume is "measured," mathematical procedures (accounting) may have to be employed to arrive at the desired volume to be "reported."

What's New in This Edition

This revised edition of *Directive 017* includes three new sections and two new appendices:

- 1.9: Measurement Schematics Requirements
- 1.10: Facility Delineation Requirements
- 4.3.3.2: Gas Lift Systems
- Appendix 9: Schematic example
- Appendix 10: Gas group delineation scenarios

Highlights of other changes:

- Section 1.2: Removed last paragraph.
- Section 1.7.2(vi): Added "vent."
- Section 2.5.2.1: Added "structural integrity of" the primary measurement element.
- Section 2.6, Table 2.1: Added the word "or" before "delivery point[s]" and "emulsion" in Note 4.
- Sections 2.6.1: Added in the first bullet "or the meter qualifies for bench proving or the meter must qualify for bench proving or be a Coriolis-type meter with sufficient structural integrity internal diagnostics" and "If there is a dump valve as part of the Coriolis or bench-proved measurement system, the dump valve must be checked for leaks at the same inspection or proving frequency set out in Table 2.1." Added in the fourth bullet "the structural integrity of" the primary measurement element.
- Section 3.2.1: Added "except for subtype 321 and 341 batteries" under Batteries.
- Section 4.2.1.2: Removed "365."
- Section 4.2.2.2: Added in gas group delineation scenarios.
- Section 4.2.2.4: Added in coalbed methane battery delineation scenarios.
- Section 4.2.2.6: Added in oil battery delivering to or receiving from a gas plant delineation scenario.
- Section 4.3.1, first paragraph: Added "or as approved by Measurement Canada."
- Section 4.3.1, item 7: Added "External gas sample analysis and density must be used to determine the gas volume at base conditions, see 4.3.2" and removed "The installation must include instrumentation that allows for continuous temperature correction."

- Section 4.3.3.1, item 10: Removed "dilution" and added "The only exception is for integrated OWMF with WP, CT, and IF facilities on the same site, in which case fuel REC is to be reported at the ABWP and total OWMF fuel use at the same facility."
- Section 4.3.4.1: Added in the fifth bullet "The exception is for clean dry sales specification gas with minimal moisture, which is acceptable not to winterize."
- Section 5.4.1: Changed Initial Qualifying Criteria item 9 from 5.0 to 30.0 m^3/month of net water production.
- Section 5.5.1: Added in measurement-by-difference scenarios for measured gas into a proration battery.
- Section 5.5.2, item 4: Added "prorated."
- Section 5.5.3.1, item 2: Added in the second bullet "if there is any Freehold objection."
- Section 5.7: Removed previous content and inserted a reference to Section 7.4.
- Section 6.2.2.4: Added in conditions for oil/emulsion double proration.
- Section 6.4.3: Added that water-cut sample and analysis must be conducted for each test.
- Section 7.4: Replaced most of this section with a newly revised version.
- Section 8.2.1: Added sample point to title and first paragraph.
- Section 8.4, Table 8.3: Added water source gas sampling requirements.
- Section 10.2: Added facility delineation scenarios.
- Section 12: Removed numbered Introduction heading and renumbered the remaining headings accordingly.
- Section 12.1.1: Under Exception, changed 0.08 to 0.07 per cent per degree Celsius.
- Section 12.3.4: Added in other means for steam meter inspection.
- Section 12.3.6: Added in exception for secondary measurement.
- Section 14.4, Table 14.3: Added "or composite meter factor (see Section 14.9)."
- Section 15.2.4: Added that wellhead meter must be used for reporting and water injection measurement scenarios.
- Appendix 1: Removed all items under development that have been completed.

In the version available on the ERCB website www.ercb.ca, all changes made since the previous edition (April 2011) appear in blue type.

Intent

This directive specifies

- what and how volumes must be measured,
- what, where, and how volumes may be estimated,
- if accounting procedures must be performed on the determined volumes and what they are,
- what data must be kept for audit purposes, and
- what resultant volumes must be reported to the ERCB.

The licensee must comply with all requirements set out in this directive.

In this directive, the term "must" indicates a requirement that must be followed. In some situations, a requirement may be subject to exceptions if specific conditions are met.

The term "should" indicates a recommendation that will not be subject to enforcement. However, the ERCB may direct the licensee in writing to implement changes to improve measurement accuracy, and this direction will become a condition of operation for that facility or facilities.

The directive does not include instructions on how the volumes must be reported to the ERCB (which are included in other ERCB documents, such as *Directive 007: Volumetric and Infrastructure requirements*), but it does include some information on requirements regarding subtype, status, and code in accordance with those documents.

Note that other sections relating to measurement listed in Appendix 1 are under development and will be added to the directive as they are completed.

If requirements in previously issued ERCB documents (interim directives, informational letters, guides, etc.) conflict with the requirements in this directive, the requirements in this directive replace the prior requirements. Over time, it is intended that all relevant superseded requirements will be rescinded.

ERCB documents fully or partially replaced by this directive are listed in the Appendix 2.

Definitions

Many terms used in this directive are defined in the Glossary (Appendix 3). However, many critically important definitions are also included within applicable sections.

Enforcement

The ERCB enforcement process is specified in *Directive 019: Compliance Assurance*. Noncompliance events are listed in the Risk Assessed Noncompliance section of *Directive 019* under the Technical Operations Group, Production Operations Section, for *Directive 017* and *Directive 007* requirements.

1 Standards of Accuracy

1.1 Introduction

With regard to accuracy, it is assumed an exact or true value exists for any variable that is valid for the conditions existing at the moment the result is determined. Determining the true value without doubt cannot be done, due to the limitations of measuring equipment and procedures and the possibility of human error. Typically, the closer one wants to approach the true value, the more expense and efforts have to be expended.

The ERCB has developed standards of accuracy for gas and liquid measurement that take into account such concerns as royalty, equity, reservoir engineering, declining production rates, and aging equipment. These standards have evolved, but originated from a 1972 Board hearing decision that determined a need for pool production accuracy standards of 2.0% for oil, 3.0% for gas, and 5.0% for water. The current standards are stated as "maximum uncertainty of monthly volume" and/or "single point measurement uncertainty." The uncertainties are to be applied as "plus/minus" (e.g., ± 5.0%). Measurement at delivery/sales points must meet the highest accuracy standards because volumes determined at these points have a direct impact on royalty determination. Other measurement points that play a role in the overall accounting process are subject to less stringent accuracy standards to accommodate physical limitations and/or economics.

The specific standards of accuracy are listed in Section 1.8.

1.2 Applicability and Use of Uncertainties

The ERCB used the uncertainty levels contained in this section to develop many of the requirements for equipment and/or procedures relating to measurement, accounting, and reporting for various aspects of oil and gas production and processing operations, which are explained in detail in other sections. **If those requirements are being met, the ERCB considers a licensee to be in compliance without the need to demonstrate compliance with the applicable uncertainty requirements contained in this section. In other words, licensees need not have any concern about the stated uncertainty limits for operations that meet minimum requirements, exception requirements, or specific ERCB approval requirements as set out in this directive. ERCB inspectors and auditors do not look for compliance with the stated uncertainty limits in conducting inspections and audits.**

In some cases a licensee may wish to deviate from the minimum requirements for equipment and/or procedures that are stated in this guide. That may be acceptable if it is in accordance with the following:

- A licensee may deviate from the minimum requirements without specific ERCB approval if no royalty, equity, or reservoir engineering concerns are associated with the volumes being measured and the licensee is able to demonstrate that the alternative measurement equipment and/or procedures will provide measurement accuracy within the applicable uncertainties. In some cases, as described in Section 5: Site-specific Deviation from Base Requirements, the licensee does not need to demonstrate compliance with the applicable uncertainties, but may instead demonstrate compliance with other specific criteria. In such cases, ERCB inspectors and auditors will review the licensees' records for demonstrated compliance with the uncertainty limits or with the other specified criteria.
- If royalty, equity, or engineering concerns are associated with the volumes being measured, a licensee may be allowed, upon application to the Technical Operations

Group of the ERCB's Field Surveillance and Operations Branch, to deviate from the minimum requirements. The application must demonstrate that the proposed alternative measurement equipment and/or procedures will either provide measurement accuracy within the applicable uncertainties or meet specific criteria described in Section 5: Site-specific Deviation from Base Requirements. Applications will also be considered if measurement accuracy will be marginally outside the uncertainty limits or specified criteria will be marginally exceeded. In such cases, ERCB inspectors and auditors will review the licensees' records for documentation to confirm that approval has been obtained to deviate from the minimum requirements and for compliance with the approval conditions.

1.3 Maximum Uncertainty of Monthly Volume

The ERCB requires production data to be reported on a calendar month basis. "Maximum uncertainty of monthly volume" relates to the limits applicable to equipment and/or procedures used to determine the total monthly volume. Total monthly volumes may result from a single month-long measurement, but more often result from a combination of individual measurements and/or estimations. For example, consider a well in an oil proration battery to which a maximum uncertainty of monthly volume would apply:

- First, the well is tested, and the oil test rate is used to estimate the well's production for the period until the next test is conducted.
- The well's total estimated oil production for the month is combined with the month's estimated oil production for the other wells in the battery to arrive at the total estimated monthly oil production for the battery.
- The total actual monthly oil production for the battery is determined based on measured deliveries out of the battery and inventory change.
- A proration factor is determined by dividing the actual battery production by the estimated battery production.
- The proration factor is multiplied by the well's estimated production to determine the well's actual monthly production.

1.4 Single Point Measurement Uncertainty

"Single point measurement uncertainty" relates to the limits applicable to equipment and/or procedures used to determine a single-phase specific volume at a single measurement point. The oil volume determined during a 24-hour well test conducted on a well in a proration battery is an example of a specific volume determination to which a single point measurement uncertainty limit would apply.

1.5 Confidence Level

The stated uncertainties are not absolute limits. The confidence level, which indicates the probability that true values will be within the stated range, is 95%. This implies that there is a 95% probability (or 19 chances in 20) that the true value will be within the stated range.

1.6 Determination of Uncertainties

The uncertainties referred to relate to the accuracies associated with measurement devices, device calibration, sample gathering and analysis, variable operating conditions, etc. These uncertainties are for single-phase specific volume determination points of specific fluids (oil, gas, or water) or for combinations of two or more such points. These uncertainties do not relate to comparisons of two or more measurement points, such as comparison of inlet volumes to outlet volumes. Such comparisons are typically expressed as proration factors, allocation factors, or metering differences.

The uncertainties are relevant to equipment at the time of installation. No uncertainty adjustment is required to account for the effects of multiphase fluids, wear, sludge or scale buildup, etc., as it is accepted that such conditions would constitute a bias error to be monitored and accounted for through the use of proration factors, allocation factors, or metering differences.

The methods to be used for determining and combining uncertainties are found in the latest edition of the American Petroleum Institute (API) *Manual of Petroleum Measurement Standards* (MPMS), Chapter 13: Statistical Aspects of Measuring and Sampling or the latest edition of the International Standard Organization (ISO) Standard 5168: Measurement of Fluid Flow—Estimation of Uncertainty of a Flow-rate Measurement.

1.6.1 Example Calculation

Determination of single point measurement uncertainty for well oil (proration battery) using "root sum square" methodology:

Individual uncertainties from historical ERCB research:

For oil/emulsion measurement,
Oil meter uncertainty = 0.5% (typical manufacturer's specification)
Meter proving uncertainty = 1.5%
Sediments and water (S&W) determination uncertainty = 0.5%
Combined uncertainty $= \sqrt{[(0.5)^2 + (1.5)^2 + (0.5)^2]}$
$= 1.66\%$ (rounded to 2.0%)
For delivery point gas measurement,
Primary measurement device – gas meter uncertainty = 1.0%
Secondary device – (pulse counter or transducer, etc.) uncertainty = 0.5%
Secondary device calibration uncertainty = 0.5%
Tertiary device – (flow calculation, EFM, etc.) uncertainty = 0.2%
Gas sampling and analysis uncertainty = 1.5%
Combined uncertainty $= \sqrt{[1.0)^2 + (0.5)^2 + (0.5)^2 + (0.2)^2 + (1.5)^2]}$
$= 1.95\%$ (rounded to 2.0%)

1.7 Explanation of Standards of Accuracy

1.7.1 Oil Systems

(i) Total battery/facility oil (delivery point measurement), including single-well batteries

For Figure 1.1,

m = single point measurement uncertainty

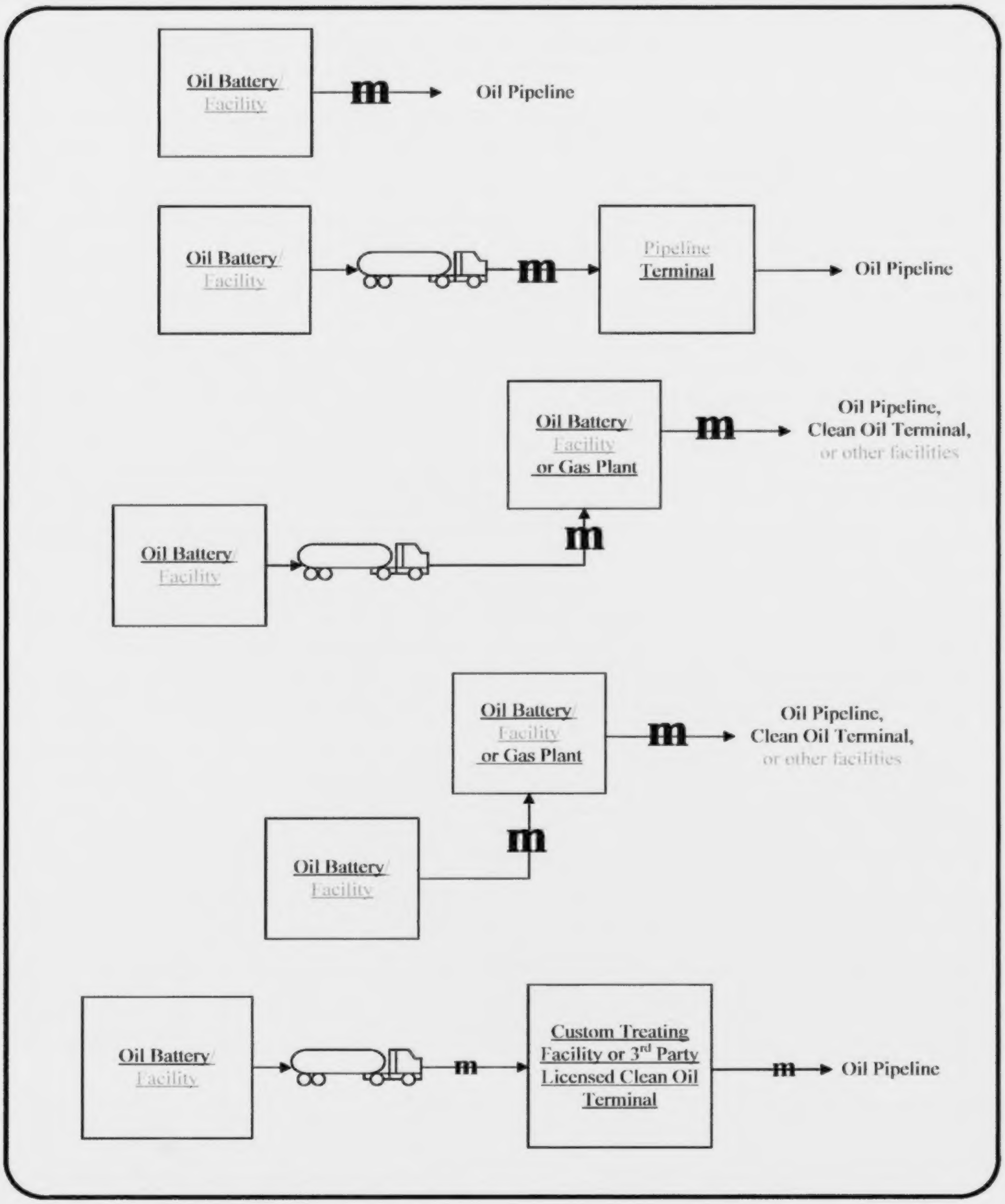

Oil Battery/ Facility
m
Oil Pipeline
Oil Battery/ Facility
m
Pipeline Terminal
Oil Pipeline
Oil Battery/ Facility or Gas Plant
m
Oil Pipeline, Clean Oil Terminal, or other facilities
Oil Battery/ Facility
m
Oil Battery/ Facility or Gas Plant
m
Oil Pipeline, Clean Oil Terminal, or other facilities
Oil Battery/ Facility
m
Oil Battery/ Facility
m
Custom Treating Facility or 3rd Party Licensed Clean Oil Terminal
m
Oil Pipeline

Figure 1.1. Total battery/facility oil (delivery point measurement)

Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending upon the number of individual measurements that are combined to yield the total monthly volume.

Single point measurement uncertainty:
Delivery point measures > 100 m^3/d = 0.5%
Delivery point measures ≤ 100 m^3/d = 1.0%

The royalty trigger point for oil is at the wellhead; thus delivery point measurements are required at the following locations:

- facility dispositions
- trucked-in receipts
- pipeline receipts
- sales
- LACT

Excluded: Test points and group points if they are not used for accounting or inventory.

(ii) Total battery gas (includes produced gas that is vented, flared, or used as fuel), including single-well batteries—also referred to as "associated gas," as it is the gas produced in association with oil production at oil wells

For Figure 1.2,
(m) = single point measurement uncertainty

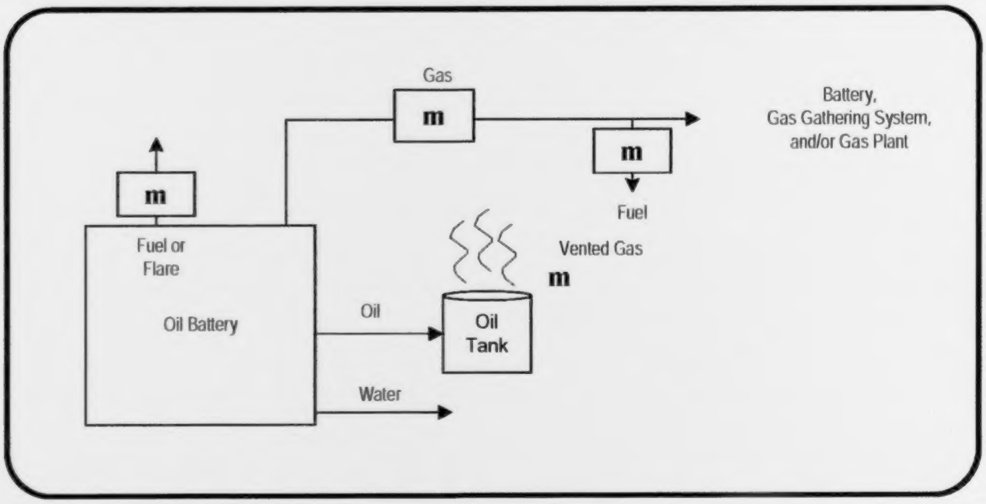


Figure 1.2

Single point measurement uncertainty:
> 16.9 10^3 m^3/d = 3.0%
> 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d = 3.0%
≤ 0.50 10^3 m^3/d = 10.0%

Maximum uncertainty of monthly volume **(M)**
> 16.9 10^3 m^3/d = 5.0%
> 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d = 10.0%
≤ 0.50 10^3 m^3/d = 20.0%
Note that **M** is dependent upon combined deliveries, fuel, and vented gas measurement.

The maximum uncertainty of total monthly battery gas volumes allows for reduced emphasis on accuracy as gas production rate declines. For gas rates up to 0.50 10^3 m^3/d, the gas volumes may be determined by using estimates; therefore, the maximum uncertainty of monthly volume is set at 20.0%. If gas rates exceed 0.50 10^3 m^3/d, the gas must be measured;

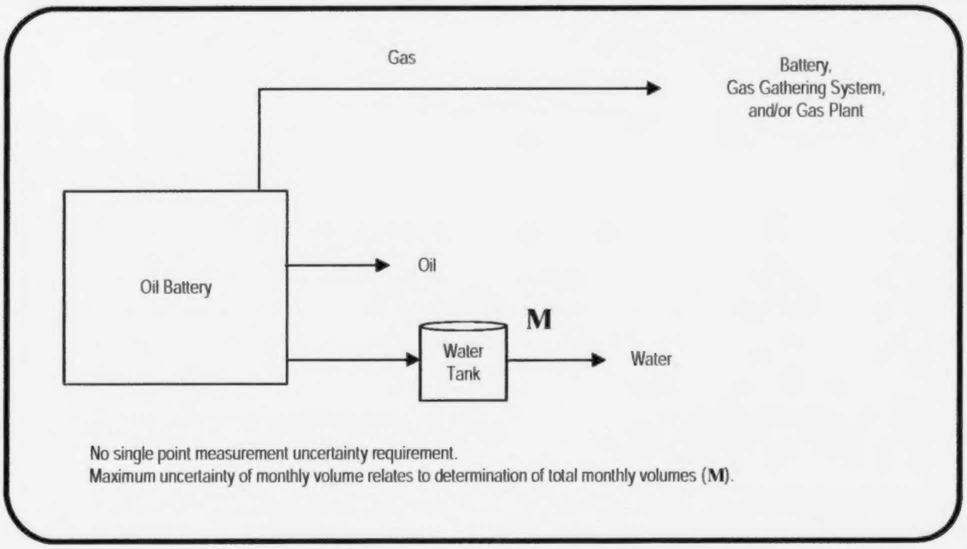
however, a component of the total monthly gas volume may include estimates for low volumes of fuel, vented, or flare gas that may add to the monthly uncertainty. At the highest gas production rates, it is expected the use of estimates will be minimal or at least have a minor impact on the accuracy of the total monthly gas volume, thereby resulting in the 5% maximum uncertainty of monthly volume.

The equipment and/or procedures used to determine the measured gas volumes (when measurement is required) must be capable of meeting a 3.0% single point measurement uncertainty. Due to the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes where rates do not exceed 0.50 10^3 m^3/d are expected to be capable of meeting a 10.0% single point measurement uncertainty.

These uncertainties do not apply to gas produced in association with heavy oil (density of 920 kg/m^3 or greater at 15°C).

(iii) Total battery water, including single-well batteries

For Figure 1.3,
M = maximum uncertainty of monthly volume



No single point measurement uncertainty requirement.
Maximum uncertainty of monthly volume relates to determination of total monthly volumes (**M**).

Figure 1.3

Maximum uncertainty of monthly volume:
> 50 m^3/month = 5.0%
≤ 50 m^3/month = 20.0%

Single point measurement uncertainty = N/A
Total battery water may be determined by measurement or estimation, depending on production rates, so no basic requirement has been set for single point measurement uncertainty.

Total battery water production volumes not exceeding 50 m^3/month may be determined by estimation; therefore, the maximum uncertainty of monthly volume is set at 20.0%.

If the total battery water production volumes exceed 50 m^3/month, the water must be separated from the oil and measured; therefore, the maximum uncertainty of monthly volume is set at 5.0%.

(iv) Well oil (proration battery)

For Figure 1.4,
(m) = single point measurement uncertainty

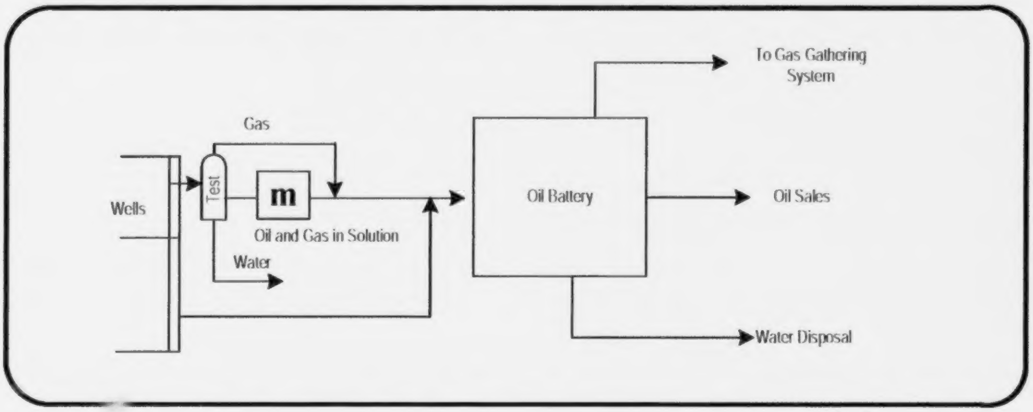


Figure 1.4

Single point measurement uncertainty:
All classes = 2.0%

Maximum uncertainty of monthly volume **(M)**:
Class 1 (high) > 30 m^3/d = 5.0%
Class 2 (medium) > 6 m^3/d but ≤ 30 m^3/d = 10.0%
Class 3 (low) > 2 m^3/d but ≤ 6 m^3/d = 20.0%
Class 4 (stripper) ≤ 2 m^3/d = 40.0%
M is dependent upon oil and gas test volumes and the number of days the test is used for estimating production, plus correction by a proration factor.

The maximum uncertainty of monthly well oil production volumes for light and medium density oil wells in proration batteries has been developed to allow for reduced emphasis on accuracy as oil production rates decline. Rather than being determined by continuous measurement, monthly well oil production volumes are estimated from well tests and corrected by the use of proration factors to result in "actual" volumes. Lower rate wells are allowed reduced testing frequencies, which, coupled with the fact that wells may exhibit erratic production rates between tests, results in less certainty that the reported monthly oil production volume will be accurate.

The equipment and/or procedures used to determine oil volumes during the well tests must be capable of meeting a 2.0% single point measurement uncertainty for all classes of wells.

These uncertainties do not apply to heavy oil wells (density of 920 kg/m^3 or greater at 15°C) in proration batteries.

(v) **Well gas (proration battery)**—also referred to as "associated gas," as it is the gas produced in association with oil production at oil wells

For Figure 1.5,
(m) = single point measurement uncertainty

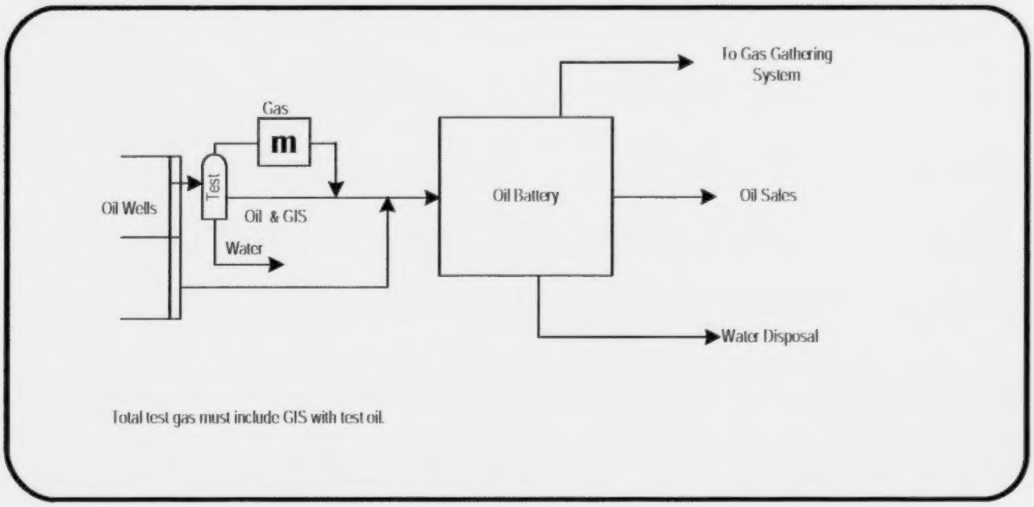


Figure 1.5

Single point measurement uncertainty:
$> 16.9\ 10^3\ m^3/d = 3.0\%$
$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d = 3.0\%$
$\leq 0.50\ 10^3\ m^3/d = 10.0\%$

Maximum uncertainty of monthly volume **(M)**:
$> 16.9\ 10^3\ m^3/d = 5.0\%$
$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d = 10.0\%$
$\leq 0.50\ 10^3\ m^3/d = 20.0\%$

M is dependent upon oil and gas test volumes and the number of days the test is used for estimating production, plus correction by a proration factor.

The maximum uncertainty of monthly oil well gas volumes has been developed to allow for reduced emphasis on accuracy as gas production rates decline. Rather than being determined by continuous measurement, monthly oil well gas production volumes are estimated from well tests and corrected by the use of proration factors to result in "actual" volumes. Low gas production rates are typically associated with wells that are allowed reduced testing frequencies, which, coupled with the fact that wells may exhibit erratic production rates between tests, results in less certainty that the reported monthly gas production volume will be accurate.

For gas rates up to $0.50\ 10^3\ m^3/d$, the well test gas volume may be determined by using estimates; therefore, the maximum uncertainty of monthly volume is set at 20.0%. If gas rates exceed $0.50\ 10^3\ m^3/d$, the test gas must be measured; however, a component of a well's total test gas volume may include estimates for solution gas dissolved in the test oil volume (gas-in-solution), which may add to the monthly uncertainty. At the highest gas production rates, it is expected that the use of estimates will be minimal or at least have a minor impact on the accuracy of the total monthly gas volume, thereby resulting in the 5.0% maximum uncertainty of monthly volume.

The equipment and/or procedures used to determine the measured test gas volumes (if measurement is required) must be capable of meeting a 3.0% single point measurement uncertainty. Due to the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes if rates do not exceed 0.50 10^3 m^3/d are expected to be capable of meeting a 10.0% single point measurement uncertainty.

These uncertainties do not apply to gas produced by heavy oil wells (density of 920 kg/m^3 or greater at 15°C) in proration batteries.

(vi) Well water (proration battery)

For Figure 1.6,
(m) = single point measurement uncertainty

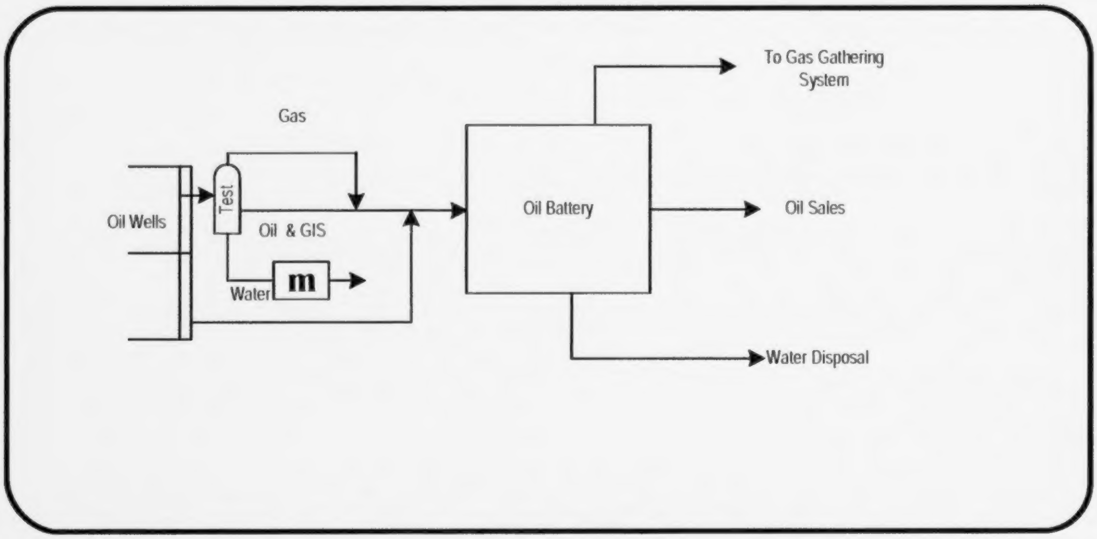


Figure 1.6

Single point measurement uncertainty = 10.0%

Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending upon the method used to determine test water rates and the frequency of well tests.

Rather than being determined by continuous measurement, monthly oil well water production volumes are estimated from well tests and corrected by the use of proration factors to result in "actual" volumes. The water rates determined during the well tests may be inferred from determining the water content of emulsion samples, and in some cases estimates may be used to determine water rates. Therefore, the single point measurement uncertainty is set at 10.0%.

These uncertainties do not apply to heavy oil wells (density of 920 kg/m^3 or greater at 15°C) in proration batteries.

1.7.2 Gas Systems

(i) Gas deliveries (sales gas)

For Figure 1.7,
(m) = single point measurement uncertainty

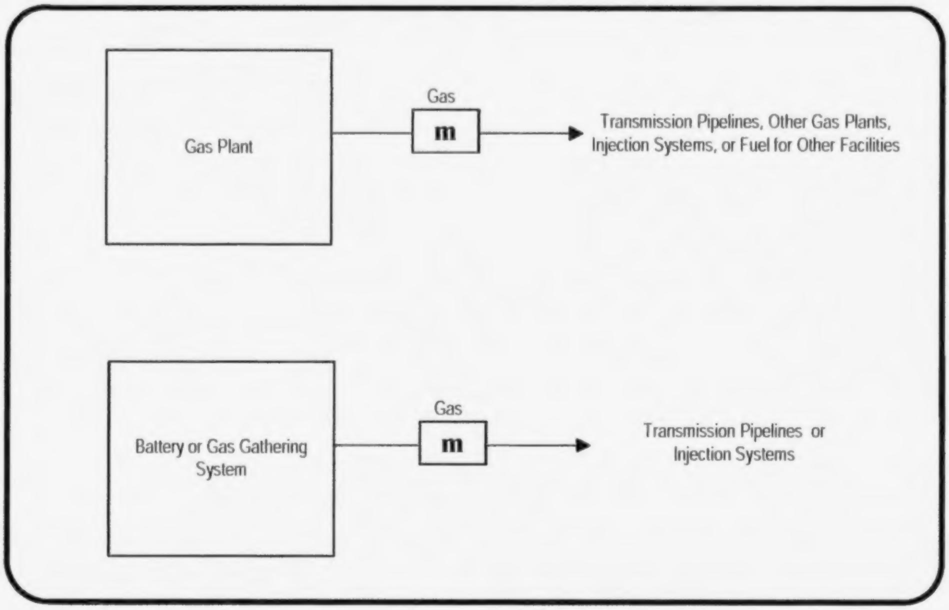

Gas Plant
Gas
m
Transmission Pipelines, Other Gas Plants, Injection Systems, or Fuel for Other Facilities
Battery or Gas Gathering System
Gas
m
Transmission Pipelines or Injection Systems

Figure 1.7

Single point measurement uncertainty = 2.0%

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

The delivery point or royalty trigger point for gas is generally for clean processed gas disposition (DISP) at the plant gate or for raw gas that is sent to another facility for FUEL usage only. The measurement at this point determines the gas volumes upon which royalties will be based. Therefore, a stringent expectation is set for the single point measurement uncertainty. In some cases, this type of gas may be delivered to other plants for further processing or to injection facilities; thus delivery point measurements are required at the following locations:

- gas plant dispositions
- sales to downstream – TCPL, ATCO, etc.
- purchase from downstream facilities – co-ops, ATCO, TCPL, etc.
- cross-border and cross-jurisdiction
- gas delivered from one upstream facility to another that is not tied to the same system for FUEL, such as from a gas battery to an oil battery
- condensate disposition to an oil facility or for sales

Excluded: Return fuel to the original source facility after the gas has been sweetened.

(ii) Hydrocarbon liquid deliveries

For Figure 1.8,
(m) = single point measurement uncertainty

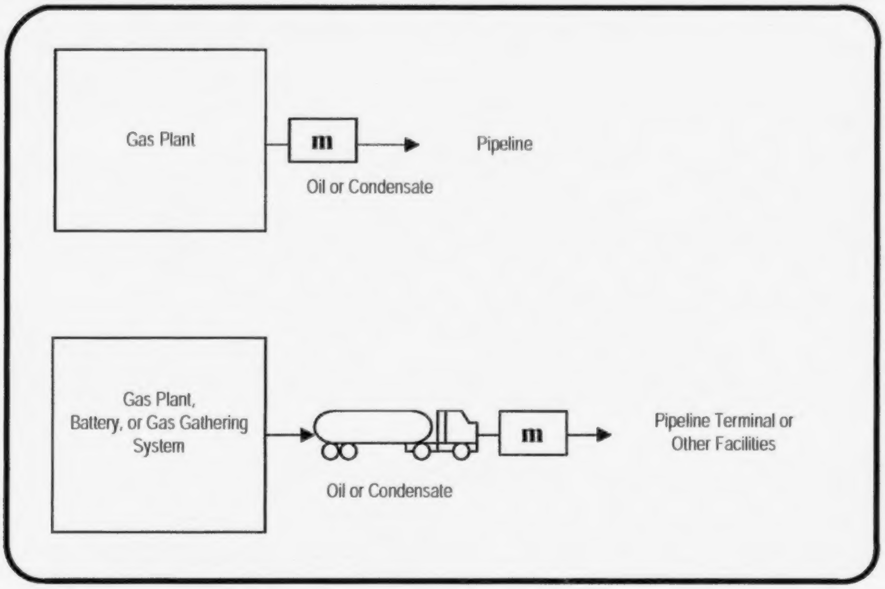

Gas Plant
m
Pipeline
Oil or Condensate
Gas Plant, Battery, or Gas Gathering System
m
Pipeline Terminal or Other Facilities
Oil or Condensate

Figure 1.8

Single point measurement uncertainty:
Delivery point measures > 100 m^3/d = 0.5%
Delivery point measures ≤ 100 m^3/d = 1.0%

Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending upon the number of individual measurements that are combined to yield the total monthly volume.

The term "delivery point measurement" for hydrocarbon liquids refers to the point at which the hydrocarbon liquid production from a battery or facility is measured. Where clean hydrocarbon liquids are delivered directly into a pipeline system (Lease Automatic Custody Transfer [LACT] measurement) or trucked to a pipeline terminal, it can also be referred to as the "custody transfer point." The "delivery point" terminology is from the perspective of the producing battery or facility, but the receiving facility (pipeline, terminal, custom treating facility, other battery, etc.) may refer to this point as its "receipt point." The hydrocarbon liquid volume determined at the delivery point is used in all subsequent transactions involving that liquid.

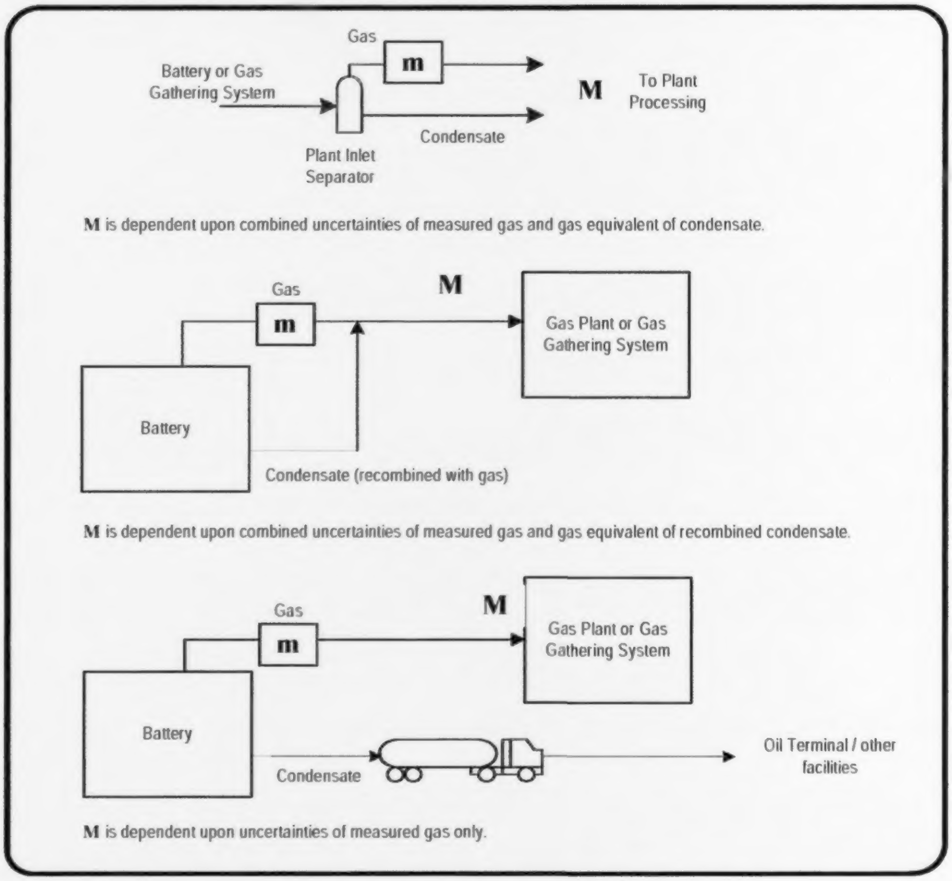
Hydrocarbon liquids delivered out of a gas system at the well, battery, or plant inlet level are typically condensate, and in some cases they may be considered to be oil. The hydrocarbon liquids delivered out of a gas plant may be pentanes plus, butane, propane, ethane, or a mixture of various components. The volumes determined at this point are the volumes upon which royalties are based.

The measurement equipment and/or procedures must be capable of determining the hydrocarbon liquid volume within the stated limits.

For facilities where the hydrocarbon liquid delivery volumes total ≤ 100 m^3/d, the single point measurement uncertainty has been increased to allow for the economical handling of hydrocarbon liquids when minimal volumes would not justify the added expense for improved measurement equipment and/or procedures.

(iii) Plant inlet or total battery/group gas

For Figure 1.9,
M = maximum uncertainty of monthly volume
(m) = single point measurement uncertainty


Gas
m
Battery or Gas Gathering System
M
To Plant Processing
Condensate
Plant Inlet Separator
Gas
M
m
Gas Plant or Gas Gathering System
Battery
Condensate (recombined with gas)
Gas
M
m
Gas Plant or Gas Gathering System
Battery
Condensate
Oil Terminal / other facilities

M is dependent upon combined uncertainties of measured gas and gas equivalent of condensate.

M is dependent upon combined uncertainties of measured gas and gas equivalent of recombined condensate.

M is dependent upon uncertainties of measured gas only.

Figure 1.9

Maximum uncertainty of monthly volume = 5.0%

Single point measurement uncertainty = 3.0%

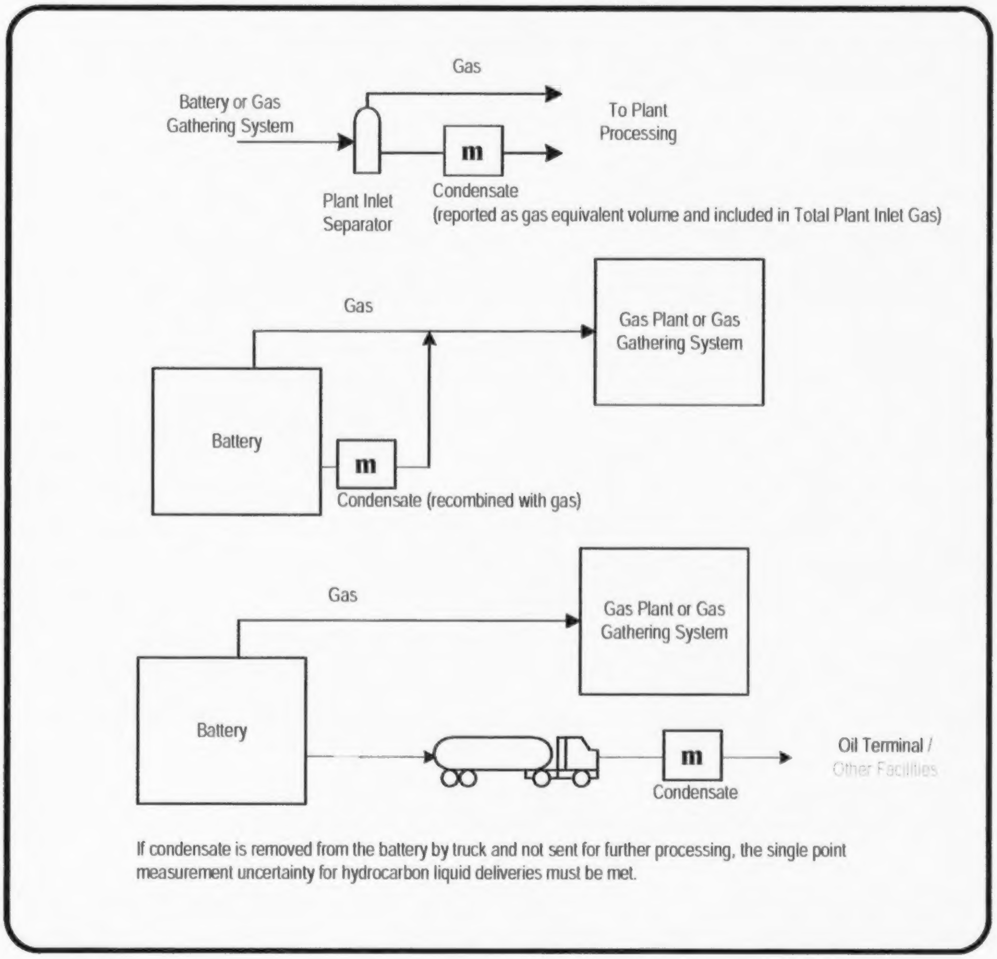
Plant inlet gas or total battery/group gas is typically unprocessed gas that may vary in composition and may contain entrained liquids. The total reported gas volume could result from combining several measured volumes from various points and may also include the calculated gas equivalent volume of entrained hydrocarbon liquids (typically condensate).

The expectation for the maximum uncertainty of monthly volume is set at 5.0% to allow for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the measured gas volumes must be capable of meeting a 3.0% single point measurement uncertainty.

(iv) Plant inlet or total battery/group condensate (recombined)

For Figure 1.10,
(m) = single point measurement uncertainty


Gas
Battery or Gas Gathering System
To Plant Processing
m
Plant Inlet Separator
Condensate
(reported as gas equivalent volume and included in Total Plant Inlet Gas)
Gas
Gas Plant or Gas Gathering System
Battery
m
Condensate (recombined with gas)
Gas
Gas Plant or Gas Gathering System
Battery
m
Condensate
Oil Terminal / Other Facilities

If condensate is removed from the battery by truck and not sent for further processing, the single point measurement uncertainty for hydrocarbon liquid deliveries must be met.

Figure 1.10

Single point measurement uncertainty = 2.0%

Maximum uncertainty of monthly volume = N/A
The condensate volume is included in the total gas volume for reporting purposes and is therefore covered by the maximum uncertainty of monthly volume for the plant inlet or total battery/group gas.

Plant inlet condensate is typically separated from the inlet stream and sent through the plant for further processing. For reporting purposes, the gas equivalent of the plant inlet condensate is included in the total plant inlet gas volume. If total battery/group condensate upstream of the plant inlet is separated and measured prior to being recombined with the gas production, the condensate is converted to a gas equivalent volume and included in the gas production volume. In either case, the condensate single point measurement uncertainty is set at 2.0% for the liquid volume determination.

Note that if plant inlet or total battery/group condensate is separated and delivered out of the system at that point, the condensate measurement is subject to the single point measurement uncertainties stipulated for hydrocarbon liquid deliveries (above).

(v) Fuel gas

For Figure 1.11,
(m) = single point measurement uncertainty

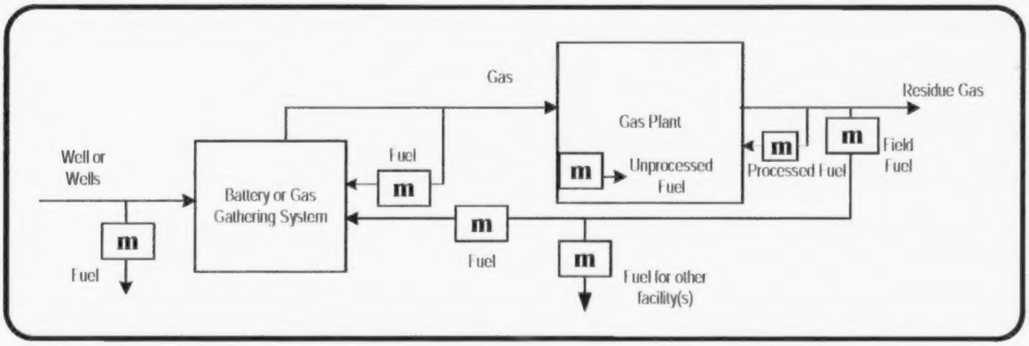


Figure 1.11

Single point measurement uncertainty:
> $0.50\ 10^3\ m^3/d = 3.0\%$
$\leq 0.50\ 10^3\ m^3/d = 10.0\%$

Maximum uncertainty of monthly volume **(M)**:
> $0.50\ 10^3\ m^3/d = 5.0\%$
$\leq 0.50\ 10^3\ m^3/d = 20.0\%$

Note that **M** is dependent upon combined uncertainties of various fuel sources at each reporting facility.

The maximum uncertainty of monthly fuel gas volumes allow for reduced emphasis on accuracy as gas flow rates decline.

For all upstream oil and gas facilities, if the annual average fuel gas rate is $0.50\ 10^3\ m^3/d$ or less on a per-site basis, the gas volume may be determined by using estimates. Therefore, the maximum uncertainty of the monthly volume is set at 20.0%. If the annual average fuel gas rates exceed $0.50\ 10^3\ m^3/d$ on any site, the gas must be measured, but since the gas being used as fuel may be unprocessed gas and part of the total fuel gas volume may include some estimated volumes (up to $0.50\ 10^3\ m^3/d$), the maximum uncertainty of the monthly volume is set at 5.0% to allow for the uncertainties associated with measuring gas under those conditions. (See Section 4.2.2.)

The equipment and/or procedures used to determine the measured gas volumes (if measurement is required) must be capable of meeting a 3.0% single point measurement uncertainty. Due to the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes if rates do not exceed 0.50 10^3 m^3/d are expected to be capable of meeting a 10.0% single point measurement uncertainty.

(vi) Flare and vent gas

For Figure 1.12,
M = maximum uncertainty of monthly volume
(m) = single point measurement uncertainty

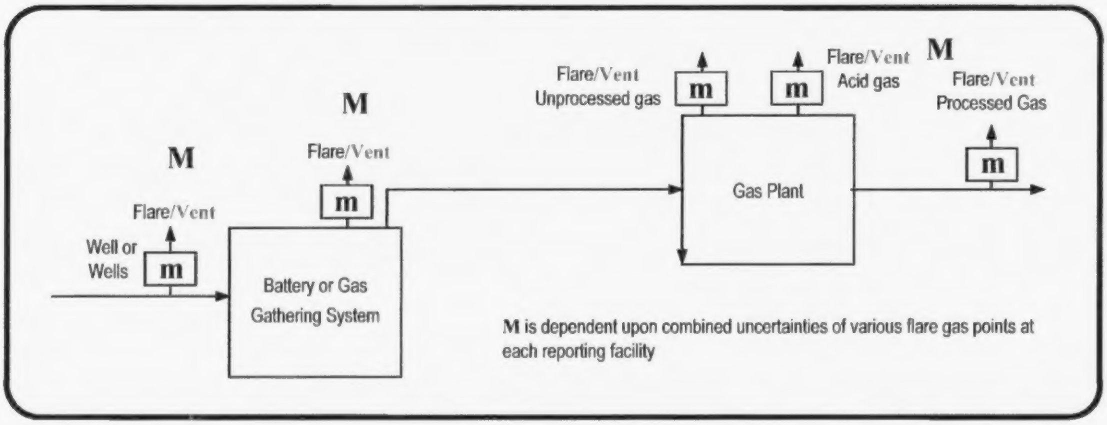

M
Flare/Vent
Well or Wells
m
M
Flare/Vent
m
Battery or Gas Gathering System
Flare/Vent Unprocessed gas
m
m
Flare/Vent Acid gas
M
Flare/Vent Processed Gas
m
Gas Plant
M is dependent upon combined uncertainties of various flare gas points at each reporting facility

Figure 1.12

Maximum uncertainty of monthly volume = 20.0%

Single point measurement uncertainty = 5.0%

Flare gas may be clean processed gas or it may be unprocessed gas, depending on the point in the system from which gas is being flared. Continuous or intermittent flare and vent sources at all oil and gas production and processing facilities (including thermal in situ facilities, but see Section 12.2.2 for cold heavy oil and crude bitumen requirements) where annual average total flared and vented volumes per facility exceed 0.5 10^3 m^3/d (excluding pilot, purge, or dilution gas) must be measured. Flare lines usually operate in a shut-in condition and may be required to accommodate partial or full volumes of gas production during flaring conditions. In some cases if flaring is infrequent and no measurement equipment is in place, flare volumes must be estimated (such as flaring at southeastern Alberta gas wells in a proration battery where there is no on-site measurement equipment). Therefore, the maximum uncertainty of the monthly volume is set at 20.0%, to allow for the erratic conditions associated with flare measurement.

The equipment and/or procedures used to determine the measured gas volumes (if measurement, not an estimate, is required) must be capable of meeting a 5.0% single point measurement uncertainty.

(vii) Acid gas

For Figure 1.13,
(m) = single point measurement uncertainty

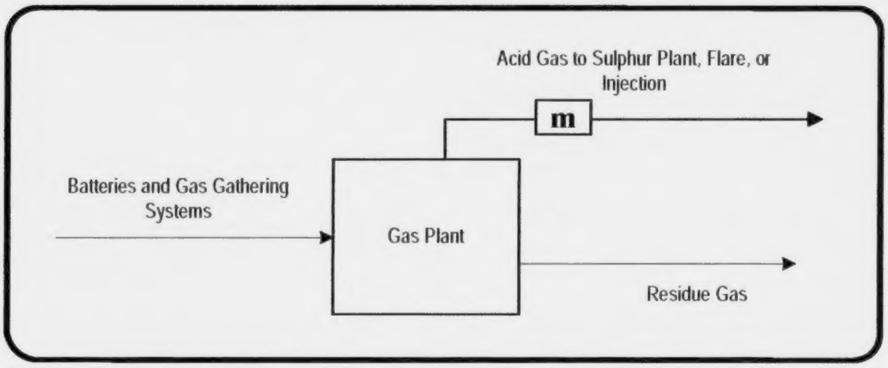

Acid Gas to Sulphur Plant, Flare, or Injection
m
Batteries and Gas Gathering Systems
Gas Plant
Residue Gas

Figure 1.13

Single point measurement uncertainty = 10.0% for low pressure acid gas before compression, and = 3.0% after compression

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

Acid gas usually contains a great deal of water vapour and has other conditions associated with it, such as very low pressure that affects measurement accuracy. Therefore, the single point measurement uncertainty is set at 10.0%.

When the acid gas is compressed and then injected into a well, the single point measurement uncertainty is set at 3.0%. (See Section 11.4.4.3 for details.)

(viii) Dilution gas

For Figure 1.14,
M = maximum uncertainty of monthly volume
(m) = single point measurement uncertainty

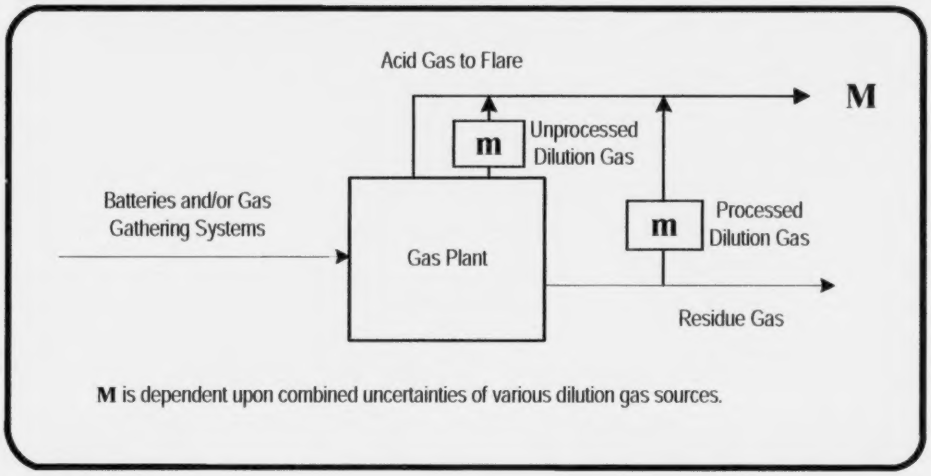

Acid Gas to Flare
M
m
Unprocessed Dilution Gas
Batteries and/or Gas Gathering Systems
Gas Plant
m
Processed Dilution Gas
Residue Gas
M is dependent upon combined uncertainties of various dilution gas sources.

Figure 1.14

Maximum uncertainty of monthly volume = 5.0%

Single point measurement uncertainty = 3.0%

Dilution gas is typically "fuel" gas used to provide adequate fuel for incineration or flaring of acid gas. Since it must be measured, it is subject to the same uncertainties as stated above for fuel gas that must be determined by measurement.

(ix) Well gas (well site separation)

For Figure 1.15,
M = maximum uncertainty of monthly volume
(m) = single point measurement uncertainty

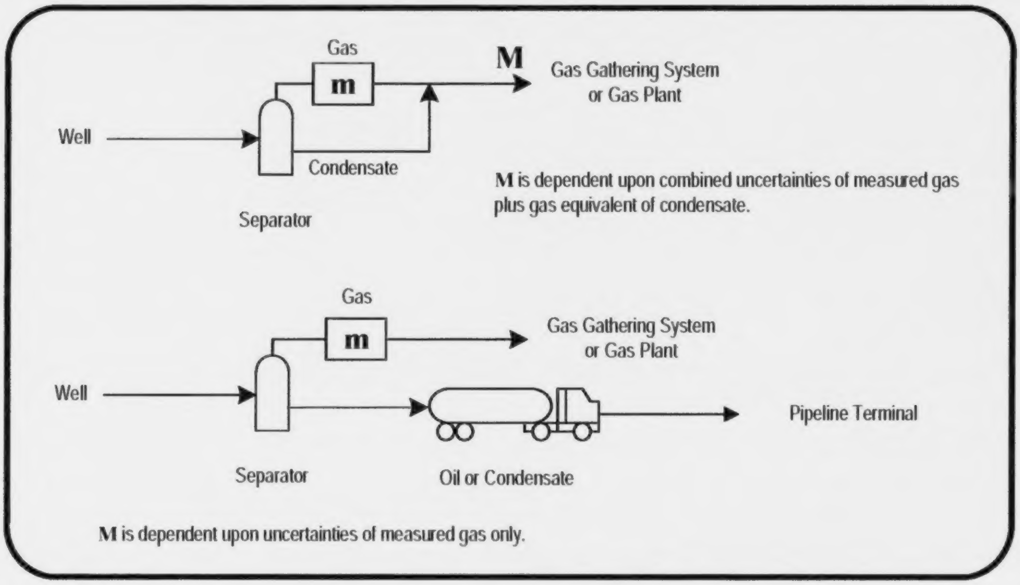

Gas
m
M
Gas Gathering System
or Gas Plant
Well
Condensate
Separator
M is dependent upon combined uncertainties of measured gas plus gas equivalent of condensate.
Gas
m
Gas Gathering System
or Gas Plant
Well
Pipeline Terminal
Separator
Oil or Condensate
M is dependent upon uncertainties of measured gas only.

Figure 1.15

Maximum uncertainty of monthly volume:
> 16.9 10^3 m^3/d = 5.0%
≤ 16.9 10^3 m^3/d = 10.0%

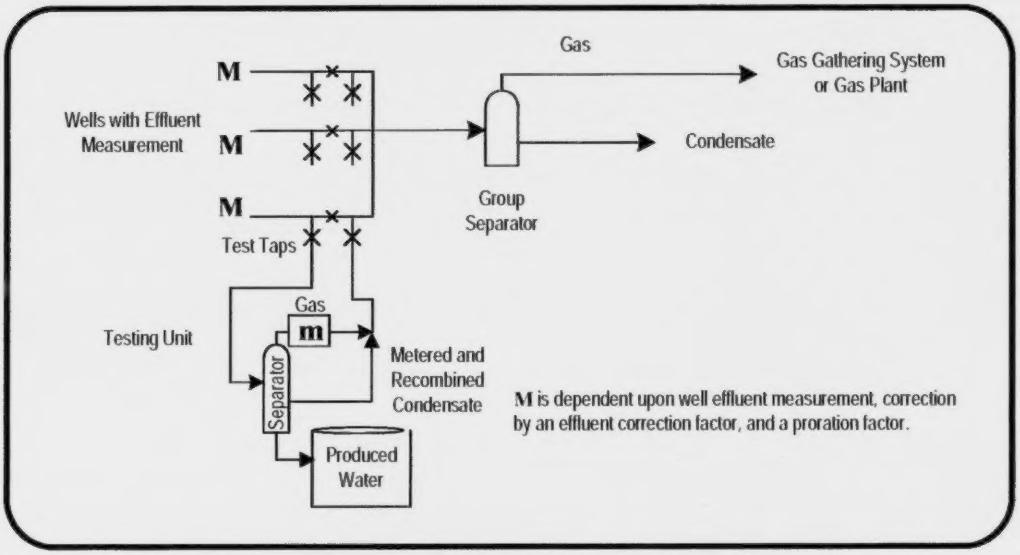
Single point measurement uncertainty = 3.0%

If production components from gas wells are separated and continuously measured, the maximum uncertainty of monthly well gas volumes allows for reduced emphasis on accuracy as gas production rates decline. Since the separated gas is unprocessed and may still contain entrained liquids at the measurement point and a component of the total reported well gas production may include the calculated gas equivalent volume of the well's condensate production, the maximum uncertainty of monthly volumes also allows for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the separated measured well gas volumes must be capable of meeting a 3.0% single point measurement uncertainty.

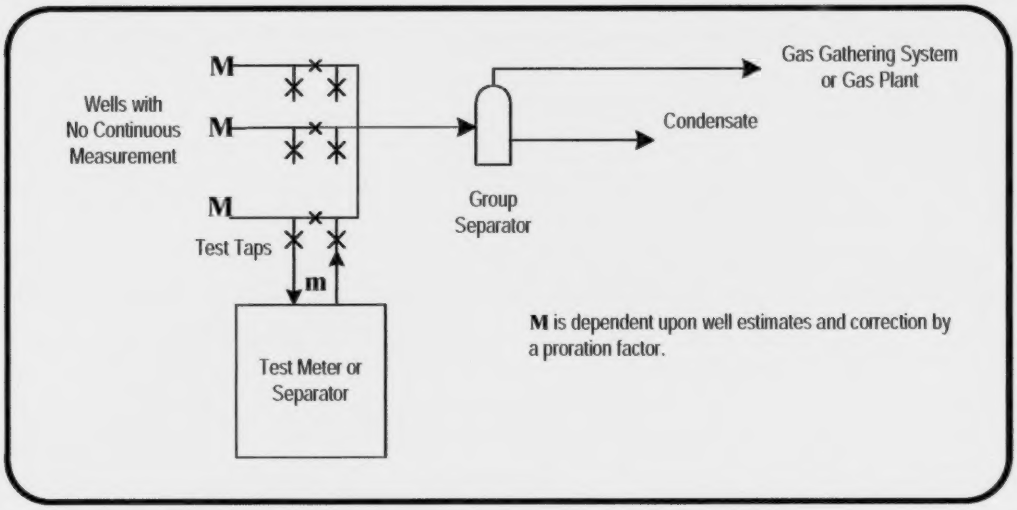
(x) Well gas (proration battery)

For Figures 1.16 and 1.17,
M = maximum uncertainty of monthly volume
(m) = single point measurement uncertainty


Gas
Gas Gathering System or Gas Plant
M
M
M
Wells with Effluent Measurement
Condensate
Group Separator
Test Taps
Gas
m
Testing Unit
Separator
Metered and Recombined Condensate
Produced Water

M is dependent upon well effluent measurement, correction by an effluent correction factor, and a proration factor.

Figure 1.16. Well gas (effluent proration battery)


Gas Gathering System or Gas Plant
M
M
M
Wells with No Continuous Measurement
Condensate
Group Separator
Test Taps
m
Test Meter or Separator

M is dependent upon well estimates and correction by a proration factor.

Figure 1.17. Well gas (Southeastern Alberta or other approved proration battery)

Maximum uncertainty of monthly volume = 15.0%

Single point measurement uncertainty = 3.0%

If production components from gas wells are not separated and continuously measured, the gas wells are subject to a proration accounting system. There are two types of gas proration batteries. "Wet" gas wells have continuous effluent measurement, and the "actual" production is prorated based on the measurement of group gas and liquid components following separation at a central location. "Dry" gas wells approved to operate without continuous measurement have the production estimated based on periodic tests, and the actual production is prorated based on the measurement of group volumes at a central location. For both types of proration batteries, the maximum uncertainty of the monthly well gas volume is set at 15.0% to allow for the inaccuracies associated with these types of measurement systems.

The equipment and/or procedures used to determine the measured well test gas volumes downstream of separation during effluent meter correction factor tests or during the periodic dry gas well tests must be capable of meeting a 3.0% single point measurement uncertainty.

(xi) Well condensate (recombined)

For Figure 1.18,
(m) = single point measurement uncertainty

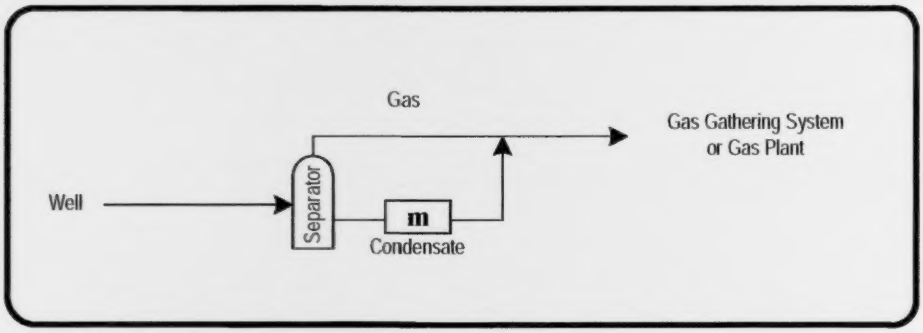


Figure 1.18

Single point measurement uncertainty = 2.0%

Maximum uncertainty of monthly volume = N/A
The gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes and is therefore covered by the monthly uncertainty for the well gas.

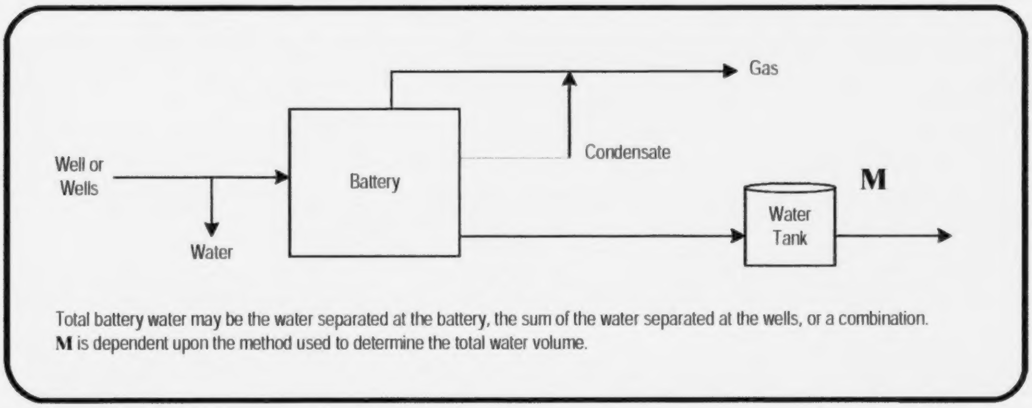
If condensate produced by a gas well is separated and measured at the wellhead prior to being recombined with the gas production, the condensate is mathematically converted to a gas equivalent volume and added to the well gas production volume. In this case, the condensate single point measurement uncertainty is set at 2.0% for the liquid volume determination. No requirement has been set for the maximum uncertainty of monthly volume because the gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes.

In the case of a gas well subject to effluent measurement, the gas equivalent of the condensate volume is included in the well's total gas production volume. The liquid volume determination, which is done during the effluent meter correction factor test, is subject to a single point measurement uncertainty of 2.0%. No requirement has been set for the maximum uncertainty of monthly volume because the gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes.

Note that if condensate produced by a gas well is separated at the wellhead and delivered out of the system at that point, the condensate is reported as a liquid volume. In this case, the condensate measurement is subject to the single point measurement uncertainties stipulated for hydrocarbon liquid deliveries (above).

(xii) Total battery water

For Figure 1.19,
M = maximum uncertainty of monthly volume



Total battery water may be the water separated at the battery, the sum of the water separated at the wells, or a combination. **M** is dependent upon the method used to determine the total water volume.

Figure 1.19

Maximum uncertainty of monthly volume = 5.0%

Single point measurement uncertainty = N/A
Total battery water may be determined by an individual group measurement, by totalling individual well measurements, or by totalling individual well estimates, so no basic requirement for measurement uncertainty has been set.

Total battery water in a gas system may be collected at a central location where it can be measured prior to disposal, or it may be a summation of individual well estimates or measurements of water collected at well sites and disposed from those sites. The 5.0% maximum uncertainty of monthly volume allows for some leeway in volume determination.

(xiii) Well water

For Figure 1.20,
(m) = single point measurement uncertainty

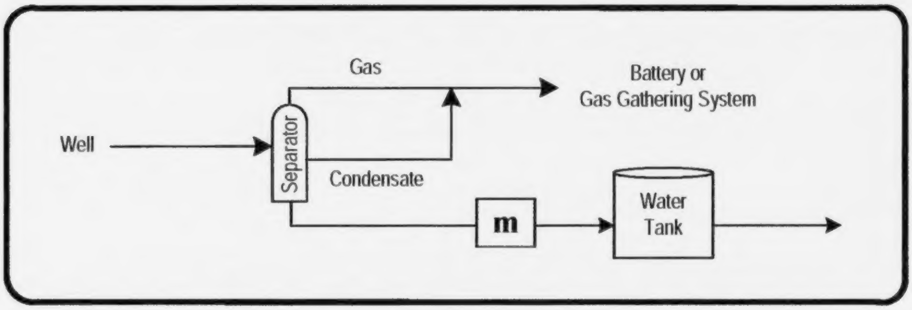


Figure 1.20

Single point measurement uncertainty = 10.0%

Maximum uncertainty of monthly volume = N/A

The uncertainty of the monthly volume will vary, depending upon whether produced volumes are subject to individual well measurement, estimation, or proration.

Water production at gas wells may be determined by measurement after separation, or if separators are not used, it may be determined by using water-gas ratios determined from engineering calculations or semiannual tests. To allow for the various methods used to determine production volumes, the single point measurement uncertainty is set at 10.0%.

1.7.3 Injection/Disposal Systems

(i) Total gas

For Figure 1.21,
M = maximum uncertainty of monthly volume

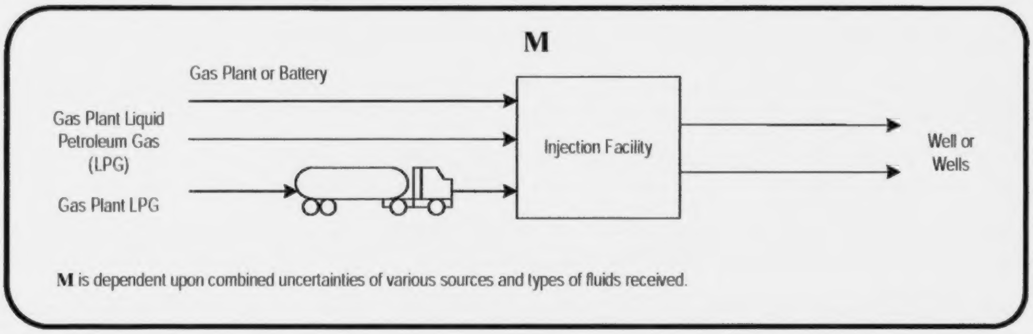

M
Gas Plant or Battery
Gas Plant Liquid Petroleum Gas (LPG)
Gas Plant LPG
Injection Facility
Well or Wells
M is dependent upon combined uncertainties of various sources and types of fluids received.

Figure 1.21

Maximum uncertainty of monthly volume = 5.0%

Single point measurement uncertainty = N/A
The single point measurement uncertainty will vary depending on the source and type of fluids received.

Gas used in injection/disposal systems may be clean processed gas or unprocessed gas that may contain entrained liquids, and in some cases several sources may make up the total gas volume received by an injection system. The expectation for the maximum uncertainty of monthly volume is set at 5.0% to allow for the uncertainties associated with measuring gas under those conditions.

(ii) Well gas

For Figure 1.22,
(m) = single point measurement uncertainty

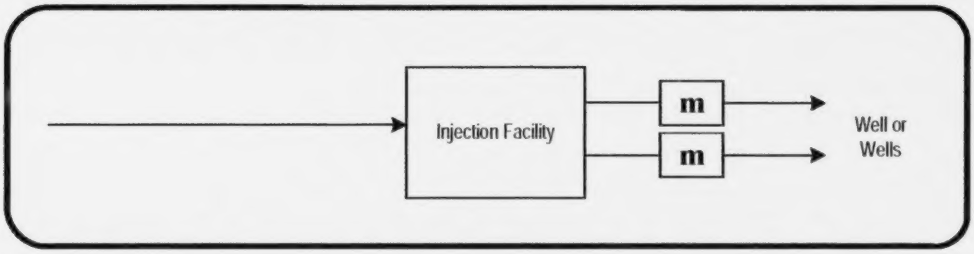

Injection Facility
m
m
Well or Wells

Figure 1.22

Single point measurement uncertainty = 3.0%

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

The gas injected/disposed into each well must be measured and may consist of clean processed gas and/or unprocessed gas that may contain entrained liquids. The equipment and/or procedures used to determine the gas volumes injected/disposed into each well must be capable of meeting a 3.0% single point measurement uncertainty.

(iii) Total water

For Figure 1.23,
M = maximum uncertainty of monthly volume

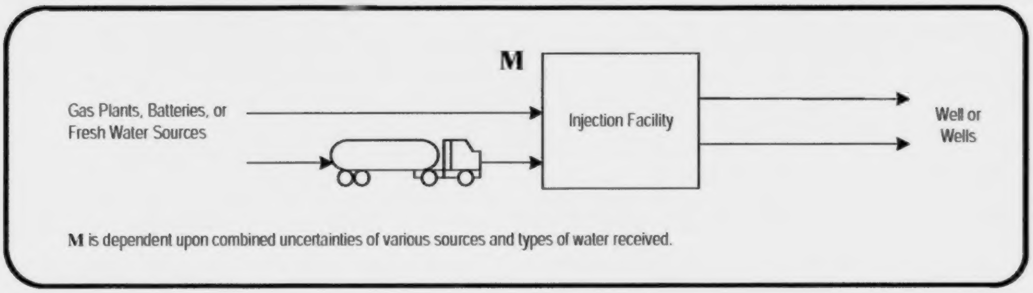

M
Gas Plants, Batteries, or Fresh Water Sources
Injection Facility
Well or Wells
M is dependent upon combined uncertainties of various sources and types of water received.

Figure 1.23

Maximum uncertainty of monthly volume = 5.0%

Single point measurement uncertainty = N/A
To be equivalent to the requirements for total oil and gas battery water.

Water used in injection/disposal systems may be produced water from oil or gas batteries, fresh water from water source wells, and/or waste water. To be equivalent to the requirements for total oil and gas battery water, the expectation for the maximum uncertainty of monthly volume is set at 5.0%.

(iv) Well water/steam

For Figure 1.24,
(m) = single point measurement uncertainty

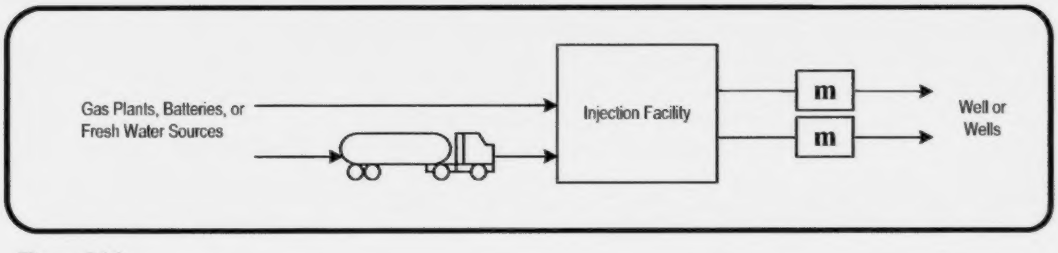

Gas Plants, Batteries, or Fresh Water Sources
Injection Facility
m
m
Well or Wells

Figure 1.24

Single point measurement uncertainty = 5.0%

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

The water/steam injected/disposed into each well must be measured. The single point measurement uncertainty is set at 5.0%. For water and steam production at a thermal in situ oil sands facility, the single point measurement uncertainty is set at 2.0% (see Sections 12.4 and 12.5 for details).

1.8 Standards of Accuracy—Summary

1.8.1 Oil Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total battery oil (delivery point measurement)		
	Delivery point measures > 100 m^3/d	N/A	0.5%
	Delivery point measures ≤ 100 m^3/d	N/A	1.0%
(ii)	Total battery gas (includes produced gas that is vented, flared, or used as fuel)		
	> 16.9 10^3 m^3/d	5.0%	3.0%
	> 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d	10.0%	3.0%
	≤ 0.50 10^3 m^3/d	20.0%	10.0%
(iii)	Total battery water		
	> 50 m^3/month	5.0%	N/A
	≤ 50 m^3/month	20.0%	N/A
(iv)	Well oil (proration battery)		
	Class 1 (high), > 30 m^3/d	5.0%	2.0%
	Class 2 (medium), > 6 m^3/d but ≤ 30 m^3/d	10.0%	2.0%
	Class 3 (low), > 2 m^3/d but ≤ 6 m^3/d	20.0%	2.0%
	Class 4 (stripper), ≤ 2 m^3/d	40.0%	2.0%
(v)	Well gas (proration battery)		
	> 16.9 10^3 m^3/d	5.0%	3.0%
	> 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d	10.0%	3.0%
	≤ 0.50 10^3 m^3/d	20.0%	10.0%
(vi)	Well water	N/A	10.0%

1.8.2 Gas Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Gas deliveries (sales gas)	N/A	2.0%
(ii)	Hydrocarbon liquid deliveries		
	Delivery point measures $>$ 100 m^3/d	N/A	0.5%
	Delivery point measures $\leq$ 100 m^3/d	N/A	1.0%
(iii)	Plant inlet or total battery/group gas	5.0%	3.0%
(iv)	Plant inlet or total battery/group condensate (recombined)	N/A	2.0%
(v)	Fuel gas		
	$>$ 0.50 10^3 m^3/d	5.0%	3.0%
	$\leq$ 0.50 10^3 m^3/d	20.0%	10.0%
(vi)	Flare and vent gas	20.0%	5.0%
(vii)	Acid gas before compression	N/A	10.0%
	Acid gas after compression		3.0%
(viii)	Dilution gas	5.0%	3.0%
(ix)	Well gas (well site separation)		
	$>$ 16.9 10^3 m^3/d	5.0%	3.0%
	$\leq$ 16.9 10^3 m^3/d	10.0%	3.0%
(x)	Well gas (proration battery)	15.0%	3.0%
(xi)	Well condensate (recombined)	N/A	2.0%
(xii)	Total battery water	5.0%	N/A
(xiii)	Well water	N/A	10.0%

1.8.3 Injection Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total gas	5.0%	N/A
(ii)	Well gas	N/A	3.0%
(iii)	Total water	5.0%	N/A
(iv)	Well water/steam	N/A	5.0%
	Produced water/steam at thermal in situ oil sands facilities	N/A	2.0%

1.9 Measurement Schematics

This section presents the requirements for measurement schematics used for measurement, accounting, and reporting of oil and gas facilities. Measurement schematics are required to ensure measurement, accounting, and reporting compliance and are a visual tool showing the current physical layout of the facility. Schematics should be regularly reviewed and used by groups such as operations, engineering, and accounting to ensure a common understanding. For the purpose of this directive, process flow diagrams (PFD), piping and instrumentation diagrams, and process and instrumentation diagrams (P&ID) are not considered measurement schematics.

Definitions:

Process flow diagram—A **PFD** is a diagram commonly used in chemical and process engineering to indicate the general flow of plant processes and equipment, including

- process piping
- major bypass and recirculation lines
- major equipment symbols, names, and identification numbers
- flow directions
- control loops that affect operation of the system
- interconnection with other systems
- system ratings and operational values as minimum, normal, and maximum flow; temperature; and pressure
- composition of fluids

Piping and instrumentation diagram—A schematic diagram showing piping, equipment, and instrumentation connections within process units.

Process and instrumentation diagram—A family of functional one-line diagrams showing hull, mechanical, and electrical systems, such as piping and cable block diagrams.

Measurement schematic—A diagram used to show the physical layout of facilities that traces the normal flow of production from left to right as it moves from wellhead through to sales. A schematic must include the elements identified in Section 1.9.1.

Field flow diagram—A line diagram showing the delineation of facilities and the connectivity of wells to compressors, gathering systems, batteries, and/or gas plants. Equipment, vessels, meters, and sample points are typically not shown on field flow diagrams. A field flow diagram contains

- well location by unique well identifier (UWI)
- producing company
- well type (oil or gas), and if gas, wet or dry measured
- compressors complete with legal survey location (LSL)
- facility codes
- final destination – battery, plant, etc.

1.9.1 Measurement Schematics Requirements

The operator is responsible for creating, confirming, and revising any measurement schematics. The schematics must be used by Operations and Production Accounting to ensure that the reported volumes are in compliance with the ERCB reporting and licensing requirements. How the required information, see below, is shown on a measurement schematic is up to the operator to decide as long as the schematic is clear and comprehensive.

The measurement schematic can be stored electronically or in hard-copy format. A master copy of the measurement schematic must be retained at a central location and previous versions must be stored for a minimum of 18 months. Note that other jurisdictions may require a longer retention time.

The measurement schematic must include the following:

- Facility name, facility licensee name, and operator name if different
- LSL of surface facility and UWI, including downhole location if different
- Facility boundaries between each reporting facility with associated PRA codes and subtypes. For larger facilities, an optional field flow diagram may be used to show facility delineation. (See Appendix 9 for an example.)
- Flow lines with flow direction that move fluids in and out of the facility(s) and those that connect the essential process equipment within the facility, including recycle lines and bypasses to measurement equipment. Identify if oil is tied into a gas system.
- Flow split or diversion points (headers) with LSL if not on a well or facility lease site
- Process equipment that change the state or composition of the fluid(s) within the facility, such as separators, treaters, dehydrators, compressors, sweetening and refrigeration units, etc.
- Measurement points and storage tanks or vessels that are used for estimating, accounting, or reporting purposes, including
    - type of measurement (meter, weight scale, or gauge)
    - type of instrumentation (charts, EFM, or readouts)
    - type of meter(s) if applicable
    - testing or proving taps required by the ERCB
- Fuel, flare, or vent take-off points – default to estimated if meter not shown
- Energy source (gas, propane, electricity) used for equipment if not measured or estimated as part of total site fuel
- Permanent flare points
- Fresh water sources, such as lakes and rivers

UWIs and LSLs are to be in a delimited format, such as 100/16-06-056-02W5/02 and 16-06-056-02W5, respectively.

Multiple facilities can be on the same page and a typical schematic may be used for wells or facilities with the same measurement configuration.

Additional information required on the schematic, as well as exceptions, is set out below.

Wells

- Include
    - all producing, water source, injection/disposal, and shut-in wells
    - reporting event for wells with downhole commingled zones
- Identify mechanical lift, such as plunger lift, pumpjack, etc. – default to well status of FLOW if not shown
- Suspended wells are optional; if shown, identify them as suspended

Process Equipment

- Include normally closed valves that can change production flow
- For compressors, identify if electric or gas drive. If gas drive, then the HP or KW rating is required unless fuel gas is measured as part of total fuel within a facility. Some cross-border facilities may be required to measure fuel for some compressors individually.
- Normally open valves, such as emergency shutdown valves (ESDs), pressure-control valves (PCVs), and block valves, are not required as they can be considered default flow
- Pressure safety valves (PSV) are not required

Measurement Points

- Identify non-accounting meters if shown
- Originating facility ID or UWI / LSL for truck-in receipt points is not required

Storage Tanks and Vessels

- Include fluid type for these tanks, vessels, and caverns, such as oil, emulsion, condensate, plant product, waste, or water; tank and vessel capacity may be shown on separate document and should be available upon request.
- Identify if the tank or vessel is underground or default to aboveground
- Identify optional nonreporting chemical storage or pop tanks if shown
- Identify if the tank or vessel is tied into a vapour recovery system (VRU) or flare system; default to vented

Measurement, Accounting, and Reporting Plan for Thermal In Situ Oil Sands Schemes (MARP)

- Include
    - blowdown lines
    - ponds – volume and fluid type
    - meter ID and sample point ID
    - tank gauge
    - pumps
    - secondary measurement points

1.9.2 Schematic Updates

Changes affecting reporting must be documented at the field level when they occur and communicated to the production accountant at a date set by the operator to facilitate accurate reporting before the PRA submission deadline.

- Physical changes, such as wells, piping, or equipment additions or removal, require a schematic update
- Temporary changes within the same reporting period do not require a schematic update

The master copy of the measurement schematic must be updated annually to reflect any changes or deletions. There must be verification of the revisions or, if no revisions, confirmation of no change. Documentation of the verification may be stored separately from the schematic but must be available on request.

Exceptions

Below are the simplified requirements for some battery subtypes:

For Heavy Oil/Crude Bitumen Administrative Grouping (subtype 343): The well list is not required to be on the schematic but should state how many wells are in the battery and must be available upon request.

For SE Alberta Shallow Gas Battery (subtypes 363 and 366): The well list is not required to be on the schematic but should state how many wells there are on each branch coming into the battery location and must be available upon request.

For Gas Test Battery (subtype 371) and Drilling and Completing Battery (subtype 381): No measurement schematic is required until the well is tied to a production battery and starts producing.

1.9.3 Implementation

- An initial window of two years from September 11, 2012
- No grandfathering for active facilities
- Any reactivated facility must have an up-to-date schematic within three months of reactivation or after the implementation period, whichever is later.

1.9.4 Schematic Availability

Schematics must be provided by the operator to the following external parties upon request:

- Facility licensee of the subject facility
- The company that performs the volumetric reporting for the facility
- The company that performs the product and residue gas allocations up to the allocation point(s)
- ERCB or other Alberta or cross-border regulatory bodies
- Operator of receipt/disposition points—all reporting measurement points for the facility only

1.10 Facility Delineation Requirements

Delineation of lease sites and geographic areas into reporting facilities is based on the measurement, accounting, and reporting rules described in this directive and *Directive 007*. Facility delineation requires accurate information on process flows and measurement points in the field, as well as a sound understanding of the ERCB facility definitions and subtypes outlined in *Directive 007*.

Multiple measurement points and regulatory flexibility can result in more than one way of delineating some facilities; however, the following general guidelines can be used.

- All gas and liquid received into and delivered from a facility must be continuously or batch measured in a single phase.
- Wells and the associated equipment are only linked to and reported under batteries or injection facilities.

  Crude oil/bitumen wells are linked to and reported under Crude oil /bitumen batteries.

  - Gas wells are linked to and reported under gas batteries.
  - Disposal wells are linked to and reported under disposal facilities.
  - Injection wells are linked and reported under injection facilities.
  - Source water wells may be linked to either a battery or, more commonly, the injection facility. If there is gas production, then linking to a subtype 902 battery will facilitate gas production reporting.
- Measured and prorated wells should not be linked to the same battery and must be reported under separate reporting codes.
- Except for thermal in situ schemes, facilities that use either regenerative sweetening processes or hydrocarbon liquid recovery processes must be reported as gas plants if they produce >2.0 m^3/d of hydrocarbon liquid.

2 Calibration and Proving

2.1 Definitions

For the purposes of this directive, calibration and proving have distinctly different meanings:

Calibration refers to procedures or operations that establish the accuracy of the values indicated by a measuring device as compared to the values indicated by a calibration instrument that has accuracy traceable to a suitable measuring standard. Adjustments are made, if required, to the measuring device to make it comparable to the calibration instrument. Calibration may also refer to the procedure used to determine the volume of a prover.

Proving refers to the procedures or operations whereby a prover volume is compared to an indicated meter volume (both corrected to applicable pressure and temperature conditions). The prover volume divided by the indicated meter volume yields a meter factor. The meter factor is subsequently applied to indicate meter volumes to determine the adjusted volume. If the meter is connected to an electronic readout, the meter factor may be incorporated into the software such that the indicated meter volume is already corrected to read the adjusted volume. (Care should be taken in such cases not to apply the meter factor again. In such cases, the meter factor should be indicated on the tag or label as being 1.0000.)

A **meter factor** is a dimensionless number used to correct indicated meter volumes to adjusted volumes if the two volumes differ due to operational conditions (e.g., gas entrained in liquids, meter slippage, meter wear). It is not to be confused with the "K Factor," which is the factor used to convert the number of pulses generated by a meter whose operation is based on electronic pulse technology into units of volume. The K Factor is typically determined by the meter manufacturer and does not take into consideration all of the specific operational conditions the meter may be subjected to.

Prover refers to a device used to collect and determine the volume of a sample of fluid that has passed through a meter. Provers typically use volumetric or gravimetric means to determine the quantity of the sample.

A **prover run** refers to the operation of a prover or master meter whereby a representative volume is sampled and measured, and that sample volume is compared to the volume indicated by a meter through which the same sample has passed to determine a meter factor.

Master meter refers to a meter of known accuracy that is connected in series with another meter for the purpose of checking the accuracy of the second meter and providing a meter factor.

A **measuring standard** refers to a device used in calibration or proving that has a known value that is traceable to national reference standards maintained by the National Research Council in Ottawa, Ontario.

A **primary measurement element** refers to the part of the meter that provides an indication of flow (e.g., an orifice plate, venturi, or vortex shedder bar).

Meter element refers to any device associated with the meter (e.g., a differential, static, or temperature-sensing element, chart recorder pen, or electronic transmitters).

An **end device** refers to the device or equipment that records the various values used to calculate a volume (e.g., a chart recorder or EFM system). In the case of an EFM system, the end device may also perform the calculations necessary to arrive at the measured and corrected gas volume.

2.2 Applicability

The calibration and proving requirements stipulated in this directive are applicable to measurement devices used in Alberta to determine volumes for ERCB-required accounting and reporting purposes. These requirements are not applicable to measurement devices used only for a licensee's internal accounting purposes. The requirements are considered minimums, and a licensee may choose to apply more stringent requirements.

If a licensee wishes to deviate from these requirements or exceptions (other than applying more stringent requirements), see Section 1: Standards of Accuracy to determine if the deviation requires submission of an application to and approval by the ERCB.

2.3 Frequency

The accuracy of measurement devices may deviate over time, due to wear, changes in operating conditions, changes in ambient conditions, etc. Generally, the more important the accuracy of a measurement device is, the more frequently it must be calibrated or proved.

For the purposes of this directive, calibration or proving frequency have the following meanings:

- Calendar quarters are January to March, April to June, July to September, and October to December.
- Monthly means at least once per calendar month.
- Bimonthly means at least once every two calendar months.
- Quarterly means at least once per calendar quarter.
- Semiannually means at least once every two calendar quarters.
- Annually means at least once every four calendar quarters.
- Biennially means at least once every eight calendar quarters (once every two years).
- Triennially means at least once every twelve calendar quarters (once every three years).

Example: For an annual frequency, if the last calibration was performed in May 2006, the operator has to perform another calibration by the end of June 2007 (end of the calendar quarter).

Exceptions

1) If the use or operation of a measurement device requiring monthly or quarterly calibration/proving is suspended for a significant period (at least seven consecutive days), the scheduled calibration/proving may be delayed by the number of days the device was not in use. Documentation of the amount of time the device was not in service must be kept and made available to the ERCB on request. If this exception is being applied, the licensee must attach a tag to the meter indicating that this exception is in effect and the next scheduled calibration/proving date. This exception is not applicable to measurement devices subject to calibration/proving frequencies that are semiannual or longer.

2) If a liquid meter is removed from service for bench proving but is put "on the shelf" and not returned to service for a considerable period of time, the countdown to the next required

bench proving does not start until the meter is returned to service. The licensee must attach a tag to the meter indicating the installation date, but leaving the original proving tag intact.

3) The ERCB may request that calibration/proving of a meter be done at any time or may extend the due date for scheduled calibration/proving, depending on the specific circumstances at a measurement point.

2.4 Accuracy of Provers and Calibration Instruments

Provers and other instruments used for calibration of measurement devices must be tested for accuracy prior to first being used, immediately following (prior to being used) any repairs or alterations being conducted on them, and periodically, in accordance with the following:

- Portable provers must be calibrated biennially using measurement standards that are traceable to national standards.
- Stationary provers must be calibrated every four years using measurement standards that are traceable to national standards.
- Calibration instruments, such as manometers, thermometers, pressure gauges, deadweight testers, electronic testers, etc., must be tested for accuracy biennially against instruments having accuracy traceable to national standards.
- Master meters must be proved quarterly using a calibrated prover. The fluid used to prove the master meter must have properties similar to the fluids measured by the meters it will be used to prove. The master meter must be proved at flow rates that are comparable to the conditions it will be used for.
- The measurement uncertainty of the proving or calibrating device must be equal to or better than the uncertainty of the device being proved or calibrated.

The procedures to be followed for these accuracy tests must be designed to provide consistent and repeatable results and must take into consideration the actual operational conditions the device will encounter. To that end, the procedures must be in accordance with the following, as available and applicable (presented in order of ERCB preference from first to last):

- procedures specified by Measurement Canada (An Agency of Industry Canada),
- procedures described in the API *Manual of Petroleum Measurement Standards*,
- the device manufacturer's recommended procedures, or
- other applicable Industry-accepted procedures.

If none of the foregoing exists, the ERCB will consider applications for and may grant approval of, appropriate procedures.

Records of the foregoing accuracy tests must be kept for at least one year following the expiry of the applicable test and provided to the ERCB on request.

2.5 Gas Meters

2.5.1 General Calibration Requirements

The term "gas meter" is broadly used to describe all of the equipment or devices that are collectively used to arrive at an indication of a gas volume. Typically, various values (e.g., differential pressure, static pressure, temperature) must be determined and used to calculate a gas volume. Depending on the specific gas meter, each of those values may be determined by individual devices or equipment.

Typically, calibration of both oil and gas meter elements requires the instrumentation to be subjected to various actual pressures, temperatures, and other values that are concurrently subjected to the calibration equipment. If the end device does not indicate the same value as the calibration equipment, adjustments must be made to the meter element and/or end device.

Some meter equipment technologies may require alternative equipment and procedures for calibration, which is acceptable provided that the equipment and procedures are capable of confirming that the meter elements are functioning properly and are sensing and transmitting accurate data to the end device.

Orifice meters are commonly used to measure gas volumes in Alberta. Gas orifice meters themselves (the meter run and orifice plate-holding device) do not require calibration/proving. However, the associated meter elements and the end devices to which they are connected must be calibrated, as described in Section 2.5.3: Orifice Meters.

If devices other than orifice meters are used to measure gas, the associated meter elements and the end devices to which they are connected must be calibrated at the same frequency as orifice meters. The required procedures must be designed to provide consistent and repeatable results and must take into consideration the actual operational conditions the device will encounter. To that end, the procedures must be in accordance with the following, as available and applicable (presented in order of ERCB preference from first to last):

- procedures specified by Measurement Canada,
- procedures described in the API *Manual of Petroleum Measurement Standards* (*MPMS*),
- the device manufacturer's recommended procedures, or
- other applicable industry-accepted procedures.

If none of the foregoing exists, the ERCB will consider applications for and may grant approval of appropriate procedures.

The frequency of meter element calibration must be

- within the first calendar month of operation of a new meter,
- immediately (by the end of the calendar month) following service or repairs to the meter,
- semiannually thereafter if the meter is used in a gas plant or for sales/delivery point (royalty trigger points), see Section 1.7.2 for details, and
- annually for all other meters.

2.5.2 Gas Meter Internal Inspection

A key contributor to meter accuracy is the condition of the internal components of the gas meter. Examples of internal components are orifice plates, vortex shedder bars, and turbine rotors. The internal components must be removed from service, inspected, replaced or repaired if found to be damaged, and then placed back in service, in accordance with the following:

- The required frequency for inspection of the gas meter primary measurement element is semiannually for gas plant accounting meters and sales/delivery point (royalty trigger point) meters and annually for all other gas meters.

- Whenever possible, the inspection should be done at the same time as the calibration of the meter elements and end device, but to accommodate operational constraints the inspection may be conducted at any time, provided that the frequency requirement is met.

- Inspections must be done in accordance with procedures specified by the API, the American Gas Association (AGA), or other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate.

- A tag or label must be attached to the meter or end device that identifies the meter serial number, the date of the internal inspection, and any other relevant details (e.g., the size of the orifice plate installed in the meter).

- A detailed record of the inspection documenting the condition of the internal components found and any repairs or changes made to the internal components must be kept for at least one year and provided to the ERCB on request.

2.5.2.1 Exceptions

1) If the "as found" calibration check of the meter element (instrumentation) of a gas meter confirms that the accuracy of all readings or outputs are within ± 0.25% of full scale (with the exception of ± 1°C for the temperature element), no adjustment of the instrumentation is required.

2) If meter elements and end devices have been found to not require adjustment for three consecutive calibrations, as indicated in #1 above, the minimum time between routine calibrations may be doubled. A tag must be attached to the meter indicating that this exception is being applied and the date of the next scheduled calibration. The records of the calibrations that qualify the meter for this exception must be kept for at least one year and made available to the ERCB on request.

3) If redundant gas meters are installed for a measurement point or redundant meter elements and/or end devices are installed on a single gas meter, the minimum time between routine calibration of the meter elements and end devices may be doubled, provided that daily volumes from each end device are compared at least monthly and found to be within 0.25% of each other. If the daily volumes are not found to be within 0.25% of each other, immediate calibration of both sets of equipment is required. A tag must be attached to the meter indicating that this exception is being applied and the date of the next scheduled calibration. The records of the monthly comparisons and any calibrations that are done must be kept for at least one year and made available to the ERCB on request.

4) If rotary, turbine, or other types of gas meters with internal moving parts are used to measure gas, such as fuel gas, they must be proved at a frequency of once every seven years following an initial proving prior to installation; the calibration of related meter elements must follow Section 2.5.1. These meters must also be proved immediately following any repairs or alterations being conducted on them. The proving may be done with the meter in service, or the meter may be removed from service and proved in a shop at a pressure that is within the normal operating condition for that meter location unless it can be shown that proving at lower pressure conditions will not change the uncertainty of the meter, such as in

the case of a rotary meter. A tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, and the meter factor determined by the proving. A detailed report indicating the details of the proving operation must be either left with the meter or readily available for inspection by the ERCB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

5) For meters used in effluent (wet gas) measurement that require proving, such as a turbine meter, the proving must be performed by using a gas master meter or other provers in single-phase proving runs. For ECF-WGR testing, see Section 7.4.

6) If the internal components of gas meters have been found to be clean and undamaged for three consecutive inspections, the minimum time between inspections may be doubled. When the internal components are found to be dirty or damaged on any subsequent inspection, the frequency for inspections will revert back to the original requirement.

7) If the inspection of internal components of a gas meter requires the meter to be removed from service and there is no meter bypass installed, it is acceptable to defer a scheduled internal component inspection until the next time the gas meter run is shut down, provided that shutting down and depressuring the gas meter run to remove and inspect the internal components would be very disruptive to operations, require excessive flaring, or cause a safety concern, and

- historical internal component inspections have proven to be satisfactory, **or**
- the meter run is installed in a flow stream where the risk of internal component damage is low (e.g., sales gas, fuel gas), **or**
- the measurement system at the facility provides sufficient assurance, through volumetric and/or statistical analysis, that internal component damage will be detected in a timely manner.

8) In the case of an orifice meter, if the orifice plate is mounted in a quick-change (senior) orifice meter assembly and when attempting to conduct an inspection of the orifice plate the fitting is found to be leaking between the chambers such that the meter run must be shut down and depressured to safely remove the orifice plate, it is acceptable to defer a scheduled orifice plate inspection until the next time the gas meter run is shut down, provided that

- shutting down and depressuring the gas meter run to remove the orifice plate would be very disruptive to operations, require excessive flaring, or cause a safety concern, **and**
- the orifice meter assembly is scheduled for repairs to be conducted the next time the gas meter run is shut down to eliminate the cause of the leak and allow future scheduled orifice plate inspections to be conducted, **and**
  - historical orifice plate inspections have proven to be satisfactory, **or**
  - the meter run is installed in a flow stream where the risk of orifice plate damage is low (e.g., sales gas, fuel gas, etc.), **or**
  - the measurement system at the facility provides sufficient assurance, through volumetric and/or statistical analysis, that orifice plate damage will be detected in a timely manner.

9) Internal metering diagnostics may be used to determine if the structural integrity of the primary measurement element is within acceptable operating parameters and checked at the same required intervals as an internal inspection. Then internal inspection is not required until an alarm or error is generated by the device or as recommended by the manufacturer. The

operator must maintain documentation on the diagnostic capability of the measurement system and make it available to the ERCB on request. An initial baseline diagnostic profile must be performed and documented during the commissioning process.

10) Single phase in-line proving of the gas meter may be used to determine if the primary measurement element/meter element is within acceptable operating parameters and proved at the same required intervals as an internal inspection. Then internal inspection is not required until the uncertainty limits are exceeded.

Note that should the primary measurement element **inspections be deferred in accordance with any of the foregoing exceptions, the licensee must be able to demonstrate to the ERCB, on request, that the situation meets the conditions identified. If these exceptions are being used, that must be clearly indicated on a tag or label attached to the meter (or end device). Evidence in battery or facility logs that the internal component inspection has been scheduled for the next shutdown must be available for inspection by the ERCB. For the purposes of these exceptions, "shutdown" means any scheduled discontinuation of flow through the meter that is of sufficient duration to allow the operations needed to remove and inspect the internal component. If an unscheduled shutdown appears that it will allow sufficient time to conduct internal component inspection operations, the licensee should consider conducting those inspections prior to the conclusion of this unscheduled shutdown.**

2.5.3 Orifice Meters

The procedure for orifice meter chart recorder (meter element and end device) calibration must be in accordance with the following:

- Pen arc, linkage, pressure stops, and spacing must be inspected and adjusted, if necessary.
- The differential pressure element must be calibrated at zero, full span, and nine ascending/descending points throughout its range. A zero check of the differential under normal operating pressure must be done before and after the calibration.
- The static pressure element must be calibrated at zero, 50% of full span, and full span.
- If a temperature element is in place, the temperature element must be calibrated at three points (operating temperature, one colder temperature, and one warmer temperature are recommended).
- If a thermometer is in place and used to determine flowing gas temperature, the thermometer must be checked at two points and replaced if found to not read accurately within ± 1°C (operating temperature and one other temperature are recommended).
- If a thermometer or other temperature measuring device is not left in place (transported by an operator and used to determine flowing gas temperatures at multiple sites), the accuracy of that device must be verified at the same frequency and in the same manner as a thermometer left in place, and the record of that verification must be readily available for inspection by the ERCB.
- Subsequent to the meter calibration, a tag or label must be attached to the meter (or end device) that identifies the meter serial number and the date of the calibration.
- A detailed report indicating the tests conducted on the meter during the calibration and the conditions as found and as left must be either left with the meter (or end device) or

readily available for inspection by the ERCB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

2.5.4 EFM Calibration

The procedure for calibration of an EFM system must be in accordance with the following:

- For digital output devices, the differential pressure element must be calibrated at zero, 50% of calibrated full span, and calibrated full span.
- For analog output devices, the differential pressure element must be calibrated at zero, 50% of full span, and full span (ascending), as well as 80% and 20% (or 75% and 25%) of full span (descending).
- A zero check of the differential under normal operating pressure must be done before and after the calibration.
- The static pressure element must be calibrated at zero, 50% of full span, and full span.
- If a temperature element is in place, the temperature element must be verified at two points (operating temperature and one colder or one warmer temperature) and calibrated or replaced if found to not indicate accurately within ± 1°C.
- Subsequent to the meter calibration, a tag or label must be attached to the meter (or end device) that identifies the meter serial number and the date of the calibration.
- A detailed report indicating the tests conducted on the instruments during the calibration and the conditions as found and as left must be either left with the meter (or end device) or readily available for inspection by the ERCB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)
- If data from the instrumentation are sent to another location(s) for flow calculations via DCS, SCADA, RTU, or other means of communication, the reading of the calibration must be verified at the receipt location of such data to ensure accurate data transmission.

2.6 Liquid Meters

Oil and other liquid production (except gas well condensate under certain conditions, see Section 2.8) and disposition volumes must always be reported as liquid volumes at 15°C and either equilibrium pressure (equilibrium pressure is assumed to be atmospheric pressure at the point of production or disposition) or 101.325 kilopascals (kPa) absolute pressure. The frequency and methodology for calibrating the meter element are the same as in Section 2.5.

Meters used to measure hydrocarbons, water, and emulsions are subject to the following general proving requirements. However, there are additional specific requirements depending on the fluid types, as detailed in Sections 2.6 through 2.10.

1) The design and operation of the meter installation must ensure that the conditions of fluid flow through the meter are within the manufacturer's recommended operating range. The meter must be installed upstream of a snap acting control/dump valve, if present.
2) The size of the prover taps and operation of the prover must not restrict or alter the normal flow through the meter. Tank-type volumetric or gravimetric provers must be connected downstream of the meter and downstream of a snap acting control/dump valve,

but other provers, such as ball provers, pipe provers, or master meters, may be connected either upstream (provided there is no gas breakout) or downstream of the meter before a snap acting control/dump valve. The location of the proving taps will dictate the proving method(s) that can be used.

3) A new hydrocarbon meter must be proved within the first calendar month of operation or immediately following any repairs being conducted on the meter or any changes to the meter installation. (Note that the resultant meter factor must be applied back to the volumes measured after the commencement of operation, repair, or change). A new water meter must be proved within the first 3 months of operation or immediately following any repairs being conducted on the meter or any changes to the meter installation and no retroactive application of meter factor is required.

4) The new meter must be proved according to the frequency in Table 2.1.

Table 2.1. Meter proving frequency requirements and proving methods

		Proving method					
Application	Meter type	Pipe/ compact/ small volume prover	Master meter	Volumetric vessel/tank prover	Bench proving	Calibrate transmitter	Proving frequency
Live oil/condensate (meter at well/battery or test meter)	PD/turbine	A[1]	A	A	A[2]	N/A	Annual
	Vortex/coriolis	A[3]	A[3]	A[3]	A[2,3]	N/A	Annual
	Differential producer	N/A	N/A	N/A	N/A	A	Annual
Live oil/condensate (gas plant inlet separator or cross border)	PD/turbine	A[3]	A	A	A[2]	N/A	Semi-annual
	Vortex/coriolis	A[3]	A[3]	A[3]	A[2,3]	N/A	Semi-annual
	Differential producer	N/A	N/A	N/A	N/A	A	Semi-annual
Dead oil, stable HVP liquids, or delivery points[4]	PD/turbine	A	A	N/A	N/A	N/A	Monthly[5]
	Coriolis/ ultrasonic	A	A	N/A	N/A	N/A	Monthly[5]
Water	PD/turbine	A	A	A	A[2]	N/A	Annual
	Vortex/coriolis/ magnetic/ ultrasonic	A[3]	A[3]	A[3]	A[2,3]	NA	Annual
	Differential producer	N/A	N/A	N/A	N/A	A	Annual

[1] A = acceptable method; N/A = not applicable.

[2] See Sections 2.7.1, 2.8.2.1, and 2.10 for bench proving information.

[3] For meter proving exceptions, see Section 2.6.1.

[4] A delivery point may be emulsion, crude oil, crude bitumen, condensate, LPGs, ethane, or NGLs.

[5] If flow is less than 100 m^3/day, quarterly proving is acceptable. For other exceptions, see Section 2.6.1.

5) The meter must be proved in line at normal operating conditions unless otherwise exempted by the ERCB.

6) If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.

7) Each proving run must consist of a representative volume of the normally metered fluid being directed into the prover or through the master meter. After application of any required correction factors, the resultant volume determined by the prover or master meter is divided by the metered volume to determine the meter factor.

8) If a meter is proved after a period of regular operation, an "as found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.

9) An acceptable initial proving (the first proving of a new or repaired meter) and all subsequent proving must consist of the number of consecutive runs, each with a meter factor (MF) within the mean of all applicable runs, as specified in Table 2.2. The resultant meter factor will be the average of all the applicable run meter factors. (Proving procedures using more than the specified number of runs are allowed, provided that the licensee can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.)

Table 2.2. Proving requirements for hydrocarbons, water, and emulsions

Hydrocarbon meter type	Initial prove: number of required consecutive runs	Subsequent prove: number of required consecutive runs		Maximum MF deviation allowed from mean of all applicable runs (%)
		"As found" MF ≤ ± 0.5% of previous	"As found" MF >± 0.5% of previous	
Live oil – field proving (see 2.7)	4	1	4	1.5
Live oil – shop proving (see 2.7.1)	4	4	4	0.5
Dead oil, condensate at equilibrium, high vapour pressure liquids (see 2.7.2 & 2.8.1)	3	1	3	0.25
Live condensate – field proving (see 2.8.2)	4	1	4	2
Live condensate – shop proving (see 2.8.2.1)	4	4	4	0.5
Water – field proving (see 2.10)	4	1	4	1.5
Water – shop proving (see 2.10)	4	4	4	1.5

10) A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the ERCB. (If the detailed report is left with the meter, the requirement below relating to the tag or label is considered to be met.) If the proving involved the use of a shrinkage factor instead of degassing, a copy of the sample analysis must be attached to the proving report.

11) Subsequent to the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, the type of prover or master meter used, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.

12) LACT meters may use the proving procedure in API-MPMS, Chapter 4: Proving Systems, instead of the procedure in this section.

2.6.1 Exceptions

1) If a meter used to measure fluids at flow-line conditions is a type that uses no internal moving parts (e.g., orifice meter, vortex meter, cone meter, Coriolis meter, ultrasonic meter), it does not require proving, provided that all the following conditions are met:

   - The flow through the meter must be continuous (not intermittent) or the meter must qualify for bench proving or be a Coriolis-type meter with sufficient structural integrity internal diagnostics (see below) and maintained within the rates specified by the meter manufacturer as providing accurate measurement. If there is a dump valve as part of the Coriolis or bench-proved measurement system, the dump valve must be checked for leaks at the same inspection or proving frequency set out in Table 2.1.
   - The design and operation of the entire meter system must be in accordance with the meter manufacturer's specifications.
   - The meter element/end device(s) must be calibrated at the frequencies specified in Section 2.5, using procedures specified in Section 2.5, by the API MPMS, the AGA, the device manufacturer, or other applicable industry-accepted procedures, whichever are most appropriate and applicable.
   - The internal components of the primary meter device must be removed from service at the same frequency as indicated in Table 2.1, inspected, replaced or repaired if found to be damaged, and then placed back in service, in accordance with procedures specified by the API, the AGA, other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate. Internal metering diagnostics may be used to determine if the structural integrity of the primary measurement element is within acceptable operating parameters and checked at the same required intervals as an internal inspection. Then internal inspection is not required until an alarm or error is generated by the device or as recommended by the manufacturer. An initial baseline diagnostic profile must be performed and documented during the commissioning process. The operator must maintain documentation on the diagnostic capability of the measurement system and make that available to the ERCB on request.
   - If a meter is to be proved just like one with internal moving parts, no internal inspection is required.
   - Whenever possible, the inspection of internal components should be done at the same time as the meter end device calibration, but to accommodate operational constraints the inspection may be conducted at any time, provided the frequency requirement is met.
   - A tag or label must be attached to the meter (or end device) that identifies the primary device serial number and the date of the calibration.
   - A tag or label must be attached to the meter (or end device) that identifies the primary device serial number, the date of the internal components inspection, and any other relevant details (e.g., the size of the orifice plate installed in the meter).
   - A detailed report indicating the tests conducted on the meter during the calibration and the conditions as found and as left must be either left with the meter (or end device) or readily available for inspection by the ERCB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

- A detailed record of the internal components inspection documenting their condition as found and any repairs or changes made to them must be either left with the meter (or end device) or readily available for inspection by the ERCB. (If the detailed report is left with the meter or readily available, the foregoing requirement relating to the tag or label is considered to be met.)

2) If the volume of fluid measured by a delivery point or LACT meter does not exceed 100 m^3/d, the meter proving frequency may be extended to quarterly. The tag attached to the meter must clearly indicate that the meter measures $\leq 100\ m^3/d$ and that the meter is on a quarterly proving frequency. The required proving frequency will revert back to monthly if the meter begins measuring volumes $> 100\ m^3/d$.

3) For delivery point or LACT meters, if the meter factor has been found to be within 0.5% of the previous factor for three consecutive months, the meter proving frequency may be extended to quarterly. The tag attached to the meter must clearly indicate that the meter has been found to have consistent meter factors and is on a quarterly proving frequency. The required proving frequency will revert back to monthly whenever the meter factor determined during a proving is found to not be within 0.5% of the previous factor.

4) If a meter that required internal inspection is used to measure liquid hydrocarbons and no meter bypass is installed, it is acceptable to defer a scheduled internal component inspection until the next time the liquid meter run is shut down, provided that shutting down and depressuring the meter run to remove and inspect the internal components would be very disruptive to operations or present a safety concern and
   - historical internal component inspections have proven to be satisfactory, or
   - the meter run is installed in a flow stream where the risk of internal component damage is low (e.g., processed or filtered liquids), or
   - the measurement system at the facility provides sufficient assurance, through volumetric and/or statistical analysis, that internal component damage will be detected in a timely manner.

2.7 Oil Meters

The two basic ways that oil is measured require distinctly different proving procedures. If oil production is measured prior to being reduced to atmospheric pressure, the proving procedures must allow for the volume reduction that will occur when the gas in solution with the "live" oil is allowed to evolve upon pressure reduction. No consideration for gas in solution is required when proving meters used to measure "dead" oil.

2.7.1 Live Oil Meters

Live oil meters are typically those used to measure volumes of oil or oil/water emulsion produced through test separators, but they also include meters used to measure well or group oil or oil/water emulsions that are delivered to other batteries or facilities by pipeline prior to the pressure being reduced to atmospheric.

To account for the shrinkage that will occur at the metering point due to the gas held in solution with live oil, the proving equipment and procedures may determine the amount of shrinkage either by physically degassing the prover oil volumes or by calculating the shrinkage based on an analysis of a sample of the live oil. Calculation of shrinkage volumes is most often used to mitigate safety and environmental concerns if the live oil volumes are measured at high pressures or if the live oil contains hydrogen sulphide (H_2S).

Additional proving requirements for live oil are as follows.

1) If the proving procedure includes degassing the prover to physically reduce the pressure of the hydrocarbons to atmospheric pressure:
    - The prover must be a tank-type volumetric or gravimetric prover.
    - Each proving run must consist of a representative volume of hydrocarbons or hydrocarbons/water emulsion being directed through the meter and into the prover and the liquid volume then being reduced in pressure to atmospheric pressure. The resultant volume determined by the prover, after application of any required correction factors, is divided by the metered volume to determine the meter factor.
    - The amount of time required to degas the prover volume and arrive at a stable atmospheric pressure in the prover will vary, depending on the initial fluid pressure and the fluid characteristics.

2) If the proving procedure uses a shrinkage factor, rather than degassing, to adjust the prover volume to atmospheric conditions:
    - A shrinkage factor representative of the fluid passing through the meter must be determined and used to adjust the meter volumes to atmospheric conditions.
        - The shrinkage factor may either be incorporated into the meter factor or be applied to metered volumes after they are adjusted by the meter factor.
        - The shrinkage factor must be based upon analysis of a sample of the metered fluid taken at normal operating conditions (see Section 14.3).
    - Whenever the operating conditions at the meter experience a change that could significantly affect the shrinkage factor, a new shrinkage factor must be determined based upon analysis of a sample of the metered fluid taken at the new operating conditions. Consideration should also be given to proving the meter at the new operating conditions to determine if the meter factor has been affected.
    - When the shrinkage factor option is used, the tag attached to the meter must indicate that a shrinkage factor was used instead of degassing the prover and whether the shrinkage factor was incorporated into the meter factor or will be applied separately.

3) When proving a test oil meter, a well that is representative of the battery's average well production characteristics must be directed through the test separator for each of the four runs. If there are wells in the battery with production characteristics that vary significantly from the average, consider determining specific meter factors to be used for each of those wells.

4) In the case of a test oil meter, the meter factor must include a correction factor to adjust the metered volume to 15°C (unless the meter is temperature compensated). Although the actual fluid temperature may vary with ambient temperature, it is acceptable to assume that the temperature observed at the time of proving is reasonably representative of the temperature experienced at the meter until the next proving. This requirement does not apply to meter technologies that do not require correction for temperature.

5) In the case of a live oil delivery point meter, the meter factor must not include a correction factor for temperature. The meter must either be temperature compensated or a fluid temperature must be taken daily and the metered volume must be corrected to 15°C. This requirement does not apply to meter technologies that do not require correction for temperature.

Exceptions

1) In situations where individual well production rates are so low that proving a test oil meter in accordance with the requirements listed above would require excessive time, it is acceptable to modify the proving procedures. Complete, individual proving runs requiring more than one hour are considered excessive. The following modifications, in order of ERCB preference, may be used to reduce proving time:

   - Produce several wells through the test separator at one time to increase the volume available for the proving runs.
   - If the degassing procedure is being used, degas the first run only, and then use those data to calculate a shrinkage factor, which can be applied to subsequent runs conducted without degassing.
   - Use the highest rate well for all proving runs.
   - Conduct only three proving runs.

   Note that the detailed proving report must clearly indicate if any of the foregoing modifications was used to prove the meter.

2) A live oil meter may be removed from service and proved in a meter shop, if it meets the following:

   - If the meter is used to measure test volumes of conventional oil/emulsion, the average rate of flow of oil/emulsion of all the wells tested through the meter must be ≤ 2 m^3/d and no well may exceed 4 m^3/d of oil/emulsion production, or
   - any meter used to measure test volumes of heavy oil/emulsion (density > 920 kg/m^3) or crude bitumen may be proved in a meter shop.

3) Shop proving is to be conducted in accordance with the following in addition to the general procedure in Section 2.6 where applicable:

   - The meter installation must be inspected as follows, and corrective action must be taken when required:
     - The flow rate through the meter must be observed to verify that it is within the manufacturer's recommended operating ranges.
     - The dump valve must not be leaking (no flow registered between dumps).
   - The shop proving may be conducted with a volumetric or gravimetric prover or with a master meter, as follows:
     - Water is typically used as the proving fluid, but varsol or some other light hydrocarbon fluid may be used for the proving.
     - Corrections for the temperature and pressure of the proving fluid must be made, where applicable.

   If the gas held in solution with the fluid produced through the meter is of sufficient volume to significantly affect the fluid volume indicated by the meter, consideration should be given to determining an appropriate shrinkage factor to correct for the effect of the solution gas and provide that factor to the meter calibration shop so it may be built into the meter factor.

2.7.2 Dead Oil Meters

Dead oil meters are typically those used for delivery point (or custody transfer point) measurement of clean oil that has been degassed to atmospheric pressure. These meters may be found measuring oil being pumped from a battery into a pipeline or measuring oil being pumped from a truck into a pipeline terminal, battery, or other facility.

2.8 Condensate Meters

Condensate is subject to two different sets of measurement, accounting, and reporting rules. If condensate volumes are measured and delivered at atmospheric pressure or equilibrium pressure, the volume must be determined and reported as a liquid volume at 15°C and equilibrium pressure. (Equilibrium pressure is assumed to be either atmospheric pressure at the point of production or disposition or the actual equilibrium pressure.) If condensate volumes are measured and delivered at flow-line conditions, the volume must be determined at flow-line pressure and corrected to 15°C, but the volume is reported as a gas equivalent volume at standard conditions (101.325 kPa absolute and 15°C).

2.8.1 Condensate at Equilibrium Conditions

Meters that measure condensate stored and delivered as a liquid at atmospheric pressure or equilibrium pressure are typically "delivery point" meters and are therefore subject to the same proving requirements and exceptions applicable to meters used for dead oil measurement (see Sections 2.6 and 2.7.2).

2.8.2 Condensate at Flow-line Conditions

When a meter that requires proving is used to measure condensate at flow-line conditions, it must be subjected to the proving requirements in Section 2.6.

2.8.2.1 Exceptions

A meter used to measure condensate at flow-line conditions may be removed from service and proved in a meter shop, in accordance with the following:

- If the meter is used to measure condensate production on a continuous basis, the rate of flow through the meter must be ≤ 2 m^3/d or it must be ≤ 3 m^3/d with the gas equivalent volume of the daily condensate volume being $\leq 3.0\%$ of the daily gas volume related to the condensate production. If the meter is used on a portable test unit, there is no volume limitation, but consideration should be given to proving the meter in line if significant condensate production is observed during the test.
- The meter installation must be inspected as follows, and corrective action must be taken where required:
  - The flow rate through the meter must be observed to verify that it is within the manufacturer's recommended operating ranges.
  - The dump valve must not be leaking (no flow registered between dumps).

2.9 Other Liquid Hydrocarbon Meters

Meters used to measure other high vapour pressure liquid hydrocarbons, such as propane, butane, pentanes plus, natural gas liquid/liquid petroleum gas (NGL/LPG), etc., are subject to the same proving requirements and exceptions set out in Sections 2.6 and 2.8.1.

2.10 Water Meters

If a meter is used to measure water production, injection, or disposal or injection of other water-based fluids, in addition to the requirements in Section 2.6,

- the meter must be installed and proved within the first three months of operation (note that the meter factor may be assumed to be 1.0000 until the first proving is conducted); and
- the proving may be conducted in line at field operating conditions, or the meter may be removed from service and proved in a meter shop using water as the test fluid.

The proving may be conducted using a volumetric prover, a gravimetric prover, or a master meter.

If a meter is proved after a period of regular operation, an "as found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter. An acceptable proving must consist of four consecutive runs (one of which may be the "as found" run), each providing a meter factor within ± 1.5% of the mean of the four factors. The resultant meter factor is the average of the four applicable meter factors. (Proving procedures using more than four runs will be allowed, provided that the licensee can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.)

Following the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.

A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the ERCB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

2.11 Product Analyzers

If a product analyzer (water cut analyzer) is used to determine water production, it must be calibrated annually using procedures recommended by the manufacturer.

Following the calibration, a tag or label must be attached to the product analyzer that identifies the analyzer serial number and the date of the calibration. A detailed report indicating the calibration procedure used and the calibration details must be either left with the analyzer or readily available for inspection by the ERCB. (If the detailed report is left with the analyzer or readily available, the foregoing requirement relating to the tag or label is considered to be met.)

2.12 Automatic Tank Gauges

2.12.1 Inventory Measurement

If automatic tank gauge devices are used to indicate fluid levels in tanks for monthly inventory measurement, they must be calibrated on site within the first month of operation. The calibration procedures must be in accordance with the following, as available and applicable (presented in order of ERCB preference from first to last):

- the device manufacturer's recommended procedures,
- procedures described in the API *Manual of Petroleum Measurement Standards*, or
- other applicable industry-accepted procedures.

If none of the foregoing exists, the ERCB will consider applications for and may grant approval of appropriate procedures.

A record of the calibration must be made available to the ERCB on request.

2.12.2 Delivery Point Measurement

If automatic tank gauge devices are used to indicate fluid levels in tanks for delivery point measurement of oil or oil/water emulsion, such as truck volume receipts at batteries/facilities or batch deliveries into a pipeline, they must be calibrated on site within the first month of operation and monthly thereafter. The calibration procedures must be in accordance with the following, as available and applicable (presented in order of ERCB preference from first to last):

- the device manufacturer's recommended procedures,
- procedures described in the API Manual of Petroleum Measurement Standards, or
- other applicable industry-accepted procedures.

If none of the foregoing exists, the ERCB will consider applications for and may grant approval of appropriate procedures.

A record of the calibration must be made available to the ERCB on request.

Exception

Where the accuracy of an automatic tank gauge is found to be within 0.5% of full scale for three consecutive months, the calibration frequency may be extended to quarterly. The record of calibration must clearly indicate that the device has been found to demonstrate consistent accuracy and is on a quarterly calibration frequency. The records of the calibrations that qualify the device for this exception must be kept and made available to the ERCB on request. The calibration frequency will revert back to monthly whenever the accuracy is found to not be within 0.5% of full scale.

2.13 Using Tank Gauging for Oil Measurement

Tank gauging refers to determining levels in a tank and using those levels to calculate a volume increase or decrease in the tank. The level may be determined by using an automatic tank gauge device or by manually determining the level with a gauge tape. In either case, the volume of the tank relative to its height at any given point must be determined. This is referred to as the tank calibration, or tank strapping, and results in the creation of a tank gauge table.

2.13.1 Inventory Measurement

If tank gauging is used only for monthly inventory measurement, specific tank calibration procedures are not required. It is acceptable to use gauge tables provided by the tank manufacturer or, if those are unavailable, generic gauge tables applicable to the tank size/type being used.

2.13.2 Delivery Point Measurement

If tank gauging is used for delivery point measurement of oil or oil/water emulsion, such as truck volume receipts at batteries/facilities or batch deliveries into a pipeline, the specific tanks being used must be calibrated on site within the first month of operation and any time the tank is damaged or altered. The calibration must result in the creation of a gauge table for each tank, which must then be used in conjunction with tank gauge readings to determine volumes. Calibration procedures must be in accordance with applicable methods stipulated in the API *Manual of Petroleum Measurement Standards*.

A record of the calibration must be made available to the ERCB on request.

2.14 Weigh Scales

Weigh scales used to measure oil/water emulsion and clean oil receipts at batteries, custom treating plants, pipeline terminals, and other facilities must be approved and inspected prior to use, in accordance with Measurement Canada requirements.

Weigh scales must be tested for accuracy in accordance with the following schedule:

- monthly,
- immediately (by the end of the calendar month) following any incident in which the scale may have been damaged, and
- immediately (by the end of the calendar month) following any changes or modifications being made to the scale.
- The complete set of procedures set out by Measurement Canada for determining weigh scale accuracy must be used following any damage or modifications and at least annually.

The monthly accuracy tests may be done using the complete set of procedures set out by Measurement Canada or, as a minimum, using the following abbreviated procedure:

1) Zero check: Determine if the scale reads zero with no weight on the scale.

2) Add a 10 kg standard weight: Determine if the scale reads 10 kg.

3) Remove the 10 kg standard weight: Determine if the scale returns to zero.

4) Add a test load consisting of 10 000 kg of standard weights or, alternatively, durable object(s) of known weight (minimum 5000 kg): Determine if the scale reads the correct weight of the test load (acceptable error is ± 0.2% of the test load).

5) Add a loaded truck, typical of the loads routinely handled by the scale: Note the total weight of the test load and truck.

6) Remove the test load and note the weight of the truck alone: Determine if the scale reading correctly indicates the removal of the test load (acceptable error is ± 0.2% of the test load).

7) Remove the truck: Determine if the scale returns to zero with no weight on the scale.

If as a result of the foregoing tests the weigh scale is found to not be accurate, it must be calibrated and retested until found to be accurate and then sealed by a heavy-duty scale service company. The service company must then send a written report to Measurement Canada documenting the adjustment and/or repairs.

A detailed record of the accuracy tests and any calibration activities must be kept in close proximity to the weigh scale, retained for at least one year, and made available to the ERCB on request. This record must include the following information:

- make, model, serial number, and capacity of the weigh scale and any associated equipment,
- date of the accuracy test,
- details of the tests performed and the results noted, and
- details regarding any alterations or calibration performed on the weigh scale.

Exceptions

1) If the volume of fluid measured by a weigh scale does not exceed 100 m^3/d, the monthly accuracy test frequency may be extended to quarterly. The detailed record of the accuracy tests must clearly indicate that the weigh scale measures $\leq$ 100 m^3/d and that the weigh scale is on a quarterly testing frequency. The required testing frequency will revert back to monthly if the weigh scale begins measuring volumes in excess of 100 m^3/d.

2) If the weigh scale has been found to not require calibration adjustments for three consecutive months, the monthly accuracy test frequency may be extended to quarterly. The required accuracy test frequency will revert back to monthly whenever a quarterly accuracy test determines that the weigh scale requires calibration adjustments.

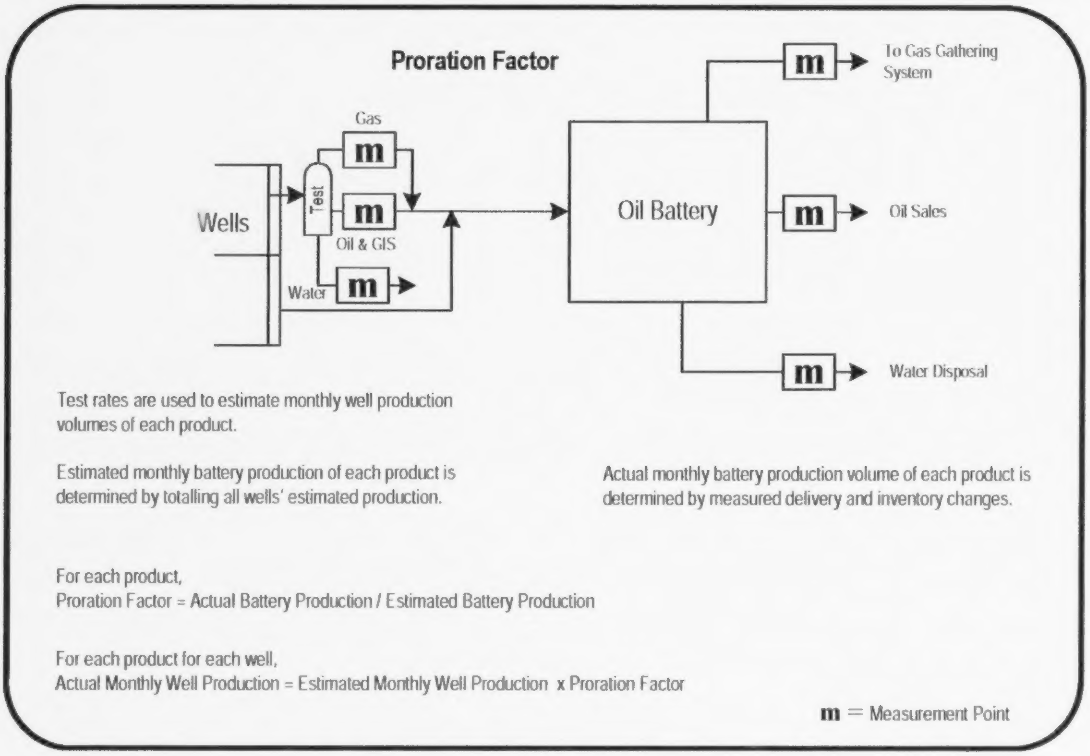
3 Proration Factors, Allocation Factors, and Metering Difference

3.1 Proration Factors and Allocation Factors

3.1.1 Description

Proration is an accounting system or procedure where the total actual monthly battery production is equitably distributed among wells in the battery. This system is applicable when the production of wells producing to a battery is commingled before separation and measurement, and each well's monthly production is initially estimated, based on well test data. In this type of system, proration factors are used to correct estimated volumes to actual volumes.

In the case of an oil proration battery (Figure 3.1), the oil, gas, and water produced by individual wells are not continuously measured. Instead, the wells are periodically tested to determine the production rates of oil, gas, and water. The rates determined during the well test are used to estimate the well's production for the time period beginning with the well test and continuing until another test is conducted. The estimated monthly production so determined for each well in the battery is totalled to arrive at the battery's total monthly estimated production. The total actual oil, gas, and water production volumes for the battery are determined, and for each fluid, the total actual volume is divided by the total estimated production to yield a "proration factor." The proration factor is multiplied by each well's estimated production to yield the well's actual production. Similar accounting procedures are used for gas batteries subject to proration.



Test rates are used to estimate monthly well production volumes of each product.

Estimated monthly battery production of each product is determined by totalling all wells' estimated production.

Actual monthly battery production volume of each product is determined by measured delivery and inventory changes.

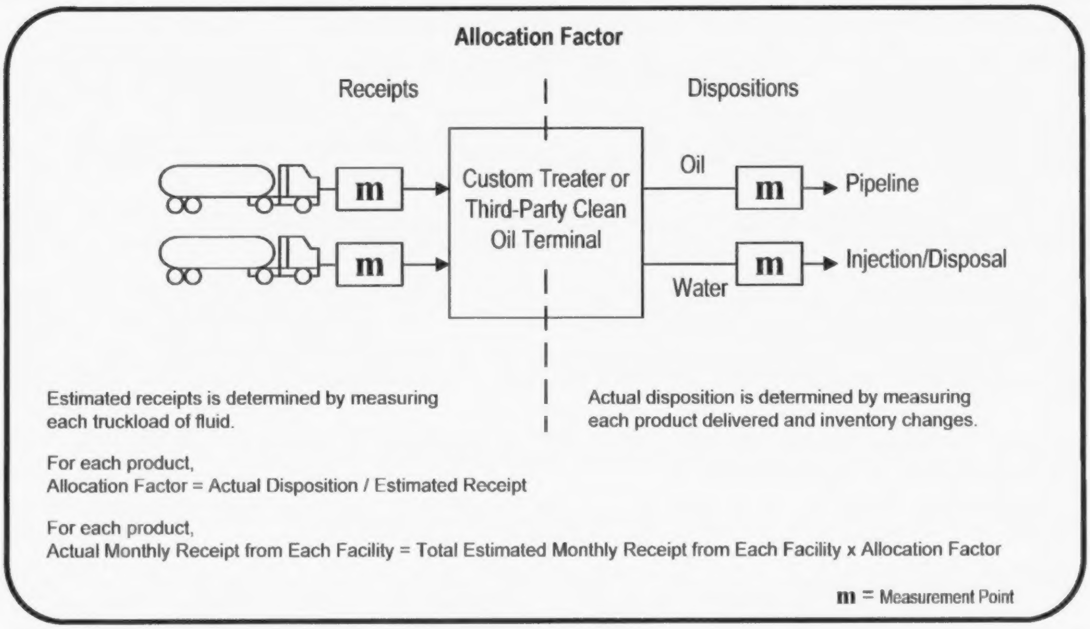
For each product,
Proration Factor = Actual Battery Production / Estimated Battery Production

For each product for each well,
Actual Monthly Well Production = Estimated Monthly Well Production x Proration Factor

m = Measurement Point

Figure 3.1

An "allocation factor" is a type of proration factor. It is used at facilities where only fluids received by truck are handled, such as custom treating plants and third-party-operated clean oil terminals (Figure 3.2). The name of the factor has been chosen to reflect the differences between batteries that receive fluids from wells through flow lines (where proration factors are used) and facilities that receive fluids from batteries only by truck (where allocation factors are used). The purpose of an allocation factor is similar to a proration factor, in that it is used to correct fluid receipt volumes (considered estimates) to actual volumes based on disposition measurements taken at the outlet of the facility (and also considering inventory change). The allocation factor is determined by dividing the monthly total actual volume for each fluid by the monthly total estimated volume for each fluid. The total estimated volume of each fluid received from each source is multiplied by the allocation factor for that fluid to yield the actual volume received from that source.


Allocation Factor

Estimated receipts is determined by measuring each truckload of fluid.

Actual disposition is determined by measuring each product delivered and inventory changes.

For each product,
Allocation Factor = Actual Disposition / Estimated Receipt

For each product,
Actual Monthly Receipt from Each Facility = Total Estimated Monthly Receipt from Each Facility x Allocation Factor

m = Measurement Point

Figure 3.2

The allocation factors discussed in this section are not to be confused with the process whereby products delivered out of a gas plant are "allocated" back to each well in the system, based on individual well production volumes and gas analyses.

Measurement accuracy and uncertainty generally relate to random errors and, as such, are not directly comparable to proration and allocation factors, which generally relate to bias errors. The ERCB Standards of Accuracy (Section 1) focus on specific measurement points (i.e., inlet or outlet), whereas proration and allocation factors relate to a comparison of inlet (or estimated production) to outlet measurement. It is important to note that target factors for different products may be different due to the products being subjected to different levels of uncertainty. For example, the target factors for oil and water in a conventional oil proration battery are different, because while the estimated production volumes of oil and water are determined by the same type of measurement, the outlet volumes of the clean oil and water are not determined by the same type of measurement.

When measurement equipment and procedures conform to all applicable standards, it is assumed that the errors that occur in a series of measurements will be either plus or minus and will cancel each other out to some degree. Where a bias error occurs in a series of measurements, there will be no plus/minus and all of the measurements are assumed to be in error by the same amount and in the same direction. Proration factors and allocation factors are therefore used to equitably correct all measurements for biased errors.

3.1.2 Target Factors

If measurement and accounting procedures meet applicable requirements, any proration factor or allocation factor should be acceptable, since it is assumed that the factor will correct for a bias error that has occurred. However, the ERCB expects proration factors and allocation factors to be monitored by operators and used as a "warning flag" to identify when the measurement system at a battery or facility is experiencing problems that need investigation.

The ERCB deems the ranges of proration factors and allocation factors indicated below to be acceptable targets. When a factor is found to exceed these limits, the licensee is expected to investigate the cause of the factor being outside the target range and document the results of the investigation and the actions taken to correct the situation. The ERCB acknowledges that in some batteries or facilities, physical limitations and/or the economics applicable to a particular situation may prohibit the resolution of situations where factors are consistently in excess of the targets indicated below. In that case, the licensee must also document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the ERCB, but must be available to the ERCB on request for audit.

If the cause of a factor being outside these ranges is determined and the error can be quantified, the ERCB expects the reported production data to be amended, thereby bringing the factor back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.

3.1.3 Exception

An exception to the foregoing procedure is allowed for conventional oil proration batteries if based on average rates determined semiannually,

- all wells in the battery produce ≤ 2 m^3/d of oil, or
- the majority of the wells in the battery produce ≤ 2 m^3/d of oil and no well produces > 6 m^3/d of oil.

In this case the licensee should still be aware of the proration factors and take corrective action where necessary, but need not expend a great deal of effort to conduct an investigation and document the results.

3.1.4 Acceptable Proration Factors and Allocation Factor Ranges

Proration Factors

Conventional oil battery (PRA subtype: 322)
- oil = 0.95000 – 1.05000
- gas = 0.90000 – 1.10000
- water = 0.90000 – 1.10000

Heavy oil battery – primary production and waterflood operations (PRA subtype: 342)
- oil = 0.85000 – 1.15000
- gas = no stated expectation due to generally low production volumes
- water = 0.85000 – 1.15000

Heavy oil battery – thermal recovery operations (PRA subtypes: 344 and 345)
- oil = 0.85000 – 1.15000
- gas = no stated expectation due to the nature of thermal production
- water = 0.85000 – 1.15000

Gas battery – SE Alberta and Outside SE Alberta Proration (PRA subtypes: 363, 364, 366, and 367)
- gas = 0.90000 – 1.10000
- water = 0.90000 – 1.10000 (subtype 364 and 367 only)

Gas battery – effluent measurement (PRA subtype: 362)
- gas = 0.90000 – 1.10000
- water = 0.90000 – 1.10000

Allocation Factors

Custom treating plant
- oil = 0.95000 – 1.05000
- water = 0.90000 – 1.10000

Clean oil terminal (third-party operated, where applicable)
- oil = 0.95000 – 1.05000

3.2 Metering Difference

3.2.1 Description

For ERCB production reporting purposes, a "metering difference" is used to balance, on a monthly basis, any difference that occurs between the measured inlet/receipt volumes and the measured outlet/disposition volumes at a facility. Metering difference is generally acceptable as an accounting/reporting entity if a difference results from two or more measurements of the same product. Metering differences occur because no two measurement devices provide the exact same volume, due to the uncertainties associated with the devices. However, a more significant cause of metering differences is that the product measured at the inlet to a facility is usually altered by the process within the facility, resulting in a different product or products being measured at the outlet of the facility. It should be noted that metering difference differs from proration and allocation factors in that for batteries or facilities where those factors are used, the difference occurs between "estimated" and "actual" volumes.

Metering difference may be used as follows:

Injection/disposal systems (Figure 3.3)—Receipts into these facilities are typically measured prior to being split up and delivered to individual wells, where each well's volume is measured prior to injection/disposal.

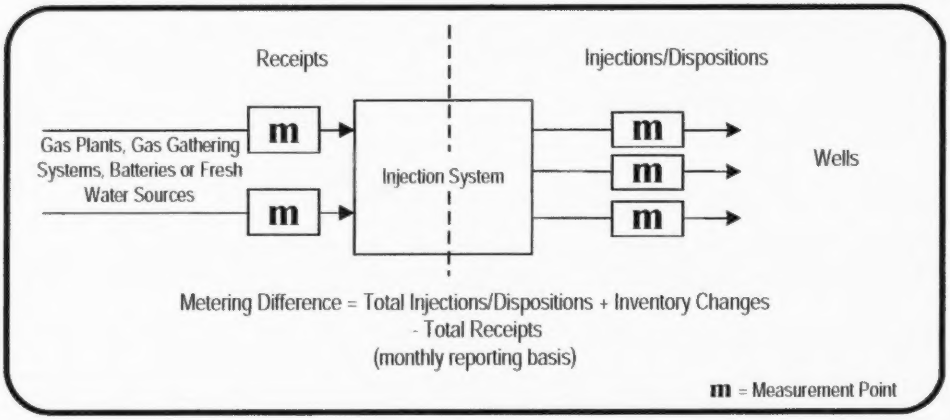

Receipts
Injections/Dispositions
Gas Plants, Gas Gathering Systems, Batteries or Fresh Water Sources
m
m
Injection System
m
m
m
Wells
Metering Difference = Total Injections/Dispositions + Inventory Changes - Total Receipts
(monthly reporting basis)
m = Measurement Point

Figure 3.3

Batteries (Figure 3.4)—Metering difference does not apply to any measured or proration battery except for subtype 321 and 341 batteries.

Gas gathering systems (Figure 3.4)—Receipts into these facilities are typically measured prior to being subjected to some sort of limited processing, which may include liquids removal and compression, and the resultant product(s) is measured prior to delivery to a sales point or to a gas plant for further processing.

Gas plants (Figure 3.4)—Receipts into these facilities are typically measured prior to being processed into salable products, and those products are measured prior to delivery to a sales point.

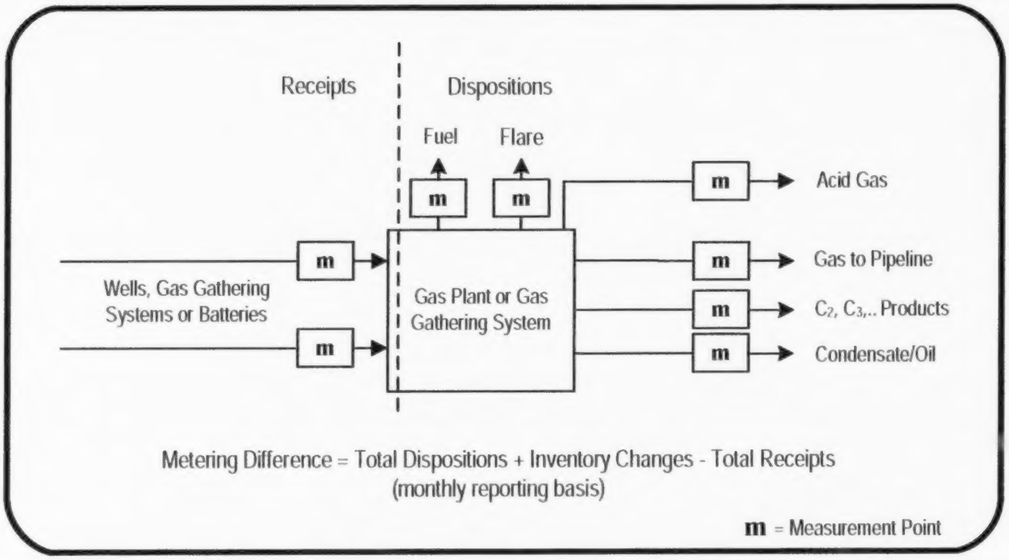

Receipts
Dispositions
Fuel
Flare
m
m
m
Acid Gas
m
Gas to Pipeline
Wells, Gas Gathering Systems or Batteries
m
m
Gas Plant or Gas Gathering System
m
C₂, C₃,.. Products
m
Condensate/Oil
Metering Difference = Total Dispositions + Inventory Changes - Total Receipts
(monthly reporting basis)
m = Measurement Point

Figure 3.4

3.2.2 Target Metering Difference

If measurement and accounting procedures meet applicable requirements, metering differences up to ± 5.0% of the total inlet/receipt volume are deemed to be acceptable. The ERCB expects the metering difference to be monitored by licensees and used as a warning flag to identify when the measurement system at a battery or facility is experiencing problems that need investigation.

When a metering difference is found to exceed 5.0%, the licensee is expected to investigate the cause of the poor metering difference and document the results of the investigation and the actions taken to correct the situation. The ERCB acknowledges that in some batteries or facilities, physical limitations and/or the economics applicable to a particular situation may prohibit the resolution of situations where the metering difference is consistently in excess of the target indicated. In such cases, the licensee must also document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the ERCB, but must be available to the ERCB on request for audit.

If the cause of a poor metering difference is determined and the error can be quantified, the ERCB expects the incorrectly reported production data to be amended, thereby bringing the metering difference back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.

4 Gas Measurement

This section presents the base requirements and exceptions for gas measurement from any source in the upstream and midstream oil and gas industry that are used for determining volumes for reporting to the ERCB.

4.1 General Requirements

All gas production and injection must be continuously and accurately measured with a measurement device or determined by engineering estimation if exception conditions described below are met or site-specific ERCB approval has been obtained.

A gas measurement system is in compliance if the following base requirements are met. A licensee may deviate from these base requirements if the conditions in Section 4.3.5: Exceptions are met. Section 1: Standards of Accuracy provides further information relating to situations when other deviations may be acceptable.

Monthly gas volumes must be reported in units of 10^3 m^3 and rounded to 1 decimal place.

Standard or base conditions for use in calculating and reporting gas volumes are 101.325 kPa (absolute) and 15°C.

4.2 Gas Measurement and Accounting Requirements for Various Battery/Facility Types

4.2.1 Oil/Bitumen Batteries

- All wells in the battery must be classified as oil or bitumen wells.
- All wells in a multiwell battery must be subject to the same type of measurement. If there is a mixture of measured and prorated wells within the same battery, ERCB exception criteria in Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" must be met or ERCB site-specific approval must be obtained.
- Production from gas batteries or other oil/bitumen batteries may not be connected to an oil/bitumen proration battery upstream of the oil/bitumen battery group gas measurement point unless specific criteria are met and/or ERCB approval of an application is obtained. See Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" for examples.

4.2.1.1 **Single-well Battery** (PRA subtypes: 311 and 331)

- Gas must be separated from oil/bitumen or emulsion and measured (or estimated where appropriate) as a single phase.

4.2.1.2 **Multiwell Group Battery** (PRA subtypes: 321 and 341)

- Each well must have its own separation and measurement equipment, similar to a single-well battery.
- All equipment for the wells in the battery must share a common surface location.

4.2.1.3 **Proration Battery** (PRA subtypes: 322, 342, 344, and 345)

- All well production is commingled prior to the total battery gas being separated from oil/bitumen or emulsion and measured (or estimated where appropriate) as a single phase.

- Individual monthly well gas production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor.

4.2.2 Gas Batteries/Facilities

- All wells in the battery must be classified as gas wells.

- Gas wells may produce condensate or oil.

- All wells in a multiwell battery must be subject to the same type of measurement. If there are mixtures of measured and prorated wells (mixed measurement) within the same battery, ERCB exception criteria in Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" must be met, or ERCB site-specific approval must be obtained, and the measured well(s) must have their own separate battery code(s) to deliver gas into the proration battery. Conversely, well(s) with no phase-separated measurement, including effluent wells, is not allowed to tie into a multiwell group battery unless there is a group measurement point before the tie-in.

- All wells in a multiwell battery must be connected by pipeline to a common point.

- Gas production from oil/bitumen wells or batteries or from other gas wells or batteries may not be connected to a gas proration battery upstream of the gas proration battery group measurement point unless ERCB exception criteria in Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" are met or ERCB site-specific approval is obtained.

- Gas wells that are designed to operate on an on/off cycle basis using plunger lifts, on/off controllers, manual on/off, etc., or pumpjacks must report well status on the PRA as GAS PUMP instead of GAS FLOW.

- Any oil and gas facility, such as a well site, gas plant, battery, or individual compressor site, that is **designed** to consume fuel gas exceeding 0.5 10^3 m^3/d on a per site basis must have fuel gas measurement from May 7, 2007, onwards. If it is a part of another facility on the same site, the overall site fuel gas used must be measured. The 0.5 10^3 m^3/d measurement limit also applies to flare and vent gas streams, excluding heavy oil and crude bitumen batteries.

4.2.2.1 Single-well Battery (PRA subtype: 351)

- Gas must be separated from water and condensate or oil (if applicable) and continuously measured as a single phase.

- Condensate produced must be reported as a liquid if it is disposed of from the well site without further processing.

- Condensate that is recombined with the gas production after separation and measurement or trucked from the well site to a gas plant for further processing must be converted to a gas equivalent volume and added to the measured single-phase gas volume for reporting purposes.

- Oil produced in conjunction with the gas must be reported as oil at stock tank conditions. The gas-in-solution (GIS) with the oil at the point of measurement must be estimated and added to the gas production volume. See Section 4.3.5.4.

4.2.2.2 Multiwell Group Battery (PRA subtypes: 361 and 365)

- **Each well must have its own separation and measurement equipment, similar to a single-well battery.**
- **The wells in the group battery may all be identical with regard to the handling of condensate** and water, **or there may be a mixture of handling methods. The rules for reporting condensate as a gas equivalent or as a liquid are the same as those for single-well gas batteries (**see Figure 4.1**).**
- The volumes measured at each well separator must be used to report the production, "PROD," volume on the PRA. There must not be any proration from any downstream measurement point.

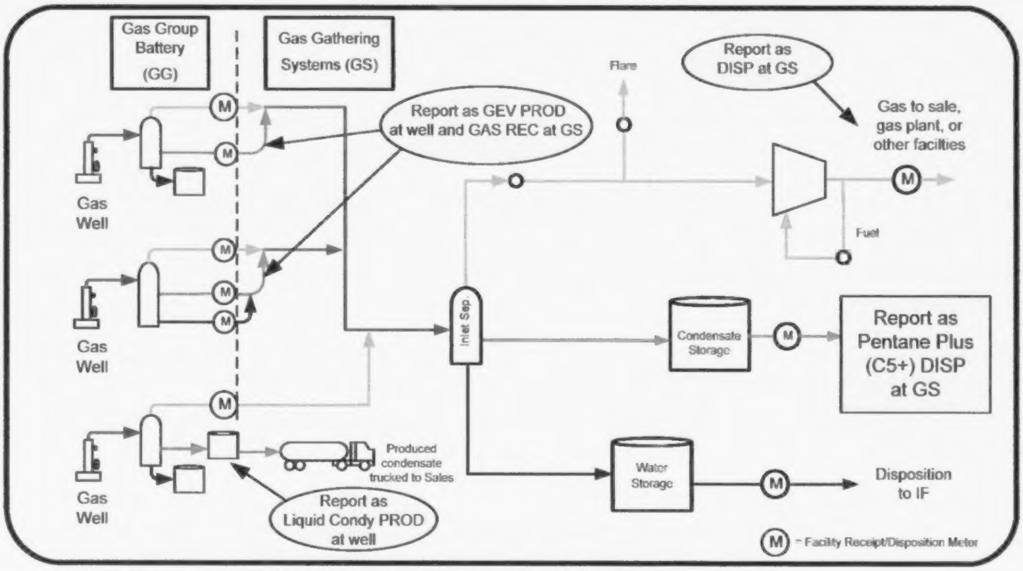

Gas Group Battery (GG)
Gas Gathering Systems (GS)
Flare
Report as DISP at GS
Gas to sale, gas plant, or other facilities
Report as GEV PROD at well and GAS REC at GS
Fuel
Gas Well
Gas Well
Gas Well
Inlet Sep.
Condensate Storage
Report as Pentane Plus (C5+) DISP at GS
Produced condensate trucked to Sales
Report as Liquid Condy PROD at well
Water Storage
Disposition to IF
M = Facility Receipt/Disposition Meter

Figure 4.1. Gas group battery delivering to a gas gathering system

There is no group measurement point requirement for fluids from the gas group wells, but the wells must deliver to a common facility, normally a GS, with the metering difference reported at the GS. Hydrocarbon liquids and/or water may be tanked and disposed of by truck and reported as liquid DISP. Recombined hydrocarbon liquids (reported as gas equivalent volume) and water (reported as liquid water) must be sent to the same common facility as the gas. Multiple gas groups can deliver to the same GS.

If the GS further disposes of the fluids, similar to the above schematic, each fluid type (gas, hydrocarbon liquids, water) disposition must be measured and reported. The GS will also report a metering difference.

When does it make sense to group wells? See Appendix 10 for case schematics.

Case 1 – 1 operator with 1 reporting entity (1 gas group)

Case 2 – 1 to 4 operators/equity partners with 4 reporting entities (4 SWB) with licensed compressor on one well

Case 3 – 1 or 2 operators with 2 reporting entities (1 SWB and 1 gas group)

Case 4 – 1 or 2 operators with 2 reporting entities (gas groups)

Case 5 – 1 or 2 operators with 2 reporting entities (gas groups) with licensed compressor on one well

4.2.2.3 **Multiwell Effluent Proration Battery** (PRA subtype: 362)

- The production from each well is subject to total effluent (wet gas) measurement, without separation of phases prior to measurement.

- Estimated well gas production is the effluent metered volume multiplied by an effluent correction factor (ECF) that is determined from periodic tests conducted at each well whereby a test separator is connected downstream of the effluent meter and the volumes measured by the test separator are compared to the volume measured by the effluent meter.

- Estimated well water production is determined by multiplying the water gas ratio (WGR), which is determined from the periodic tests, by the estimated well gas production.

- The combined (group) production of all wells in the effluent proration battery must have three-phase separation or equivalent and be measured as single-phase components, and the resulting total actual battery gas volume (including gas equivalent volume [GEV] of condensate) and total actual battery water volume must be prorated back to the wells to determine each well's actual gas and water production. If condensate is trucked out of the group separation and measurement point without further processing to a sales point, condensate production must be reported at the wellhead based on the condensate-gas ratio (CGR) from the well test. If liquid condensate is trucked to a gas plant for further processing, the condensate must be reported as a gas equivalent.

4.2.2.4 **Multiwell Proration Battery** (PRA subtypes: 363, 364, 366, and 367)

- Production from the wells in the battery is commingled prior to separation and measurement at a central location.

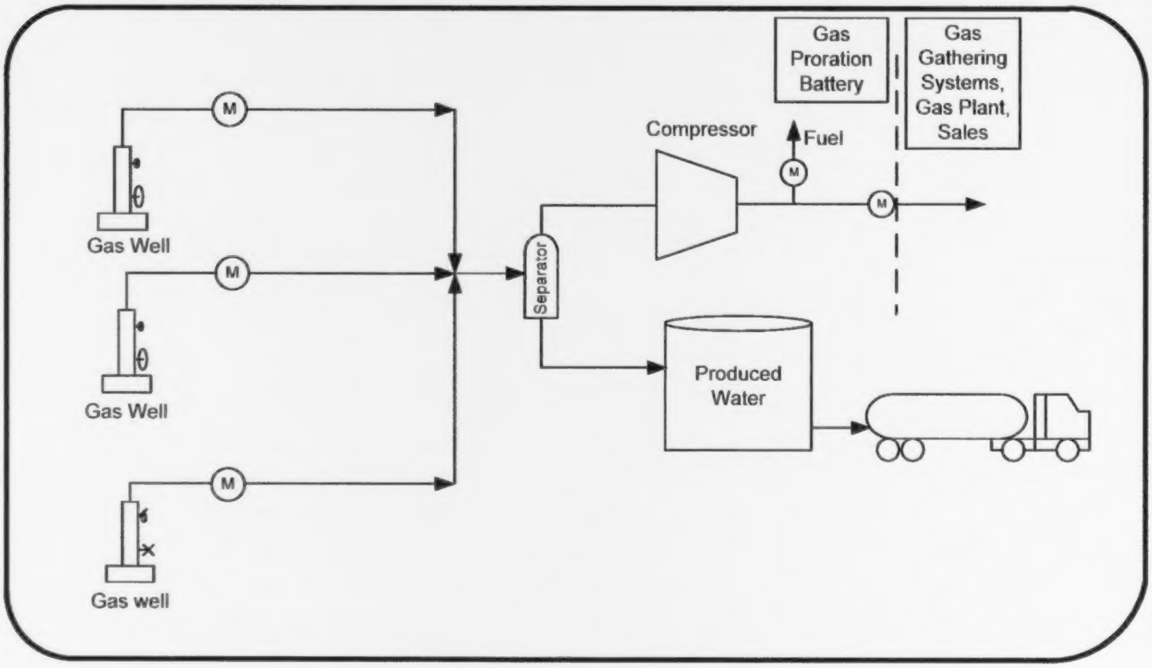
- Production from each well is not continuously measured, but is estimated based on periodic tests conducted at each well.

- The combined production of all wells in the proration battery must be separated and measured as single-phase components, and the resulting total actual battery gas volume (including GEV of condensate) and total actual battery water volume must be prorated back to the wells to determine each well's actual gas and water production.

- Gas wells that meet specific criteria applicable to Southeastern (SE) Alberta Shallow Gas Wells (see Section 7.2) may be grouped in a proration battery without specific approval. For those batteries, water volumes do not need to be prorated back to individual wells.

- Gas wells that do not meet the specific criteria applicable to SE Alberta Shallow Gas Wells may only be grouped in a proration battery if the conditions specified in Section 5: Site-specific Deviation from Base Requirements are met or if ERCB site-specific approval of an application is obtained.

Scenario 1



Gas Proration Battery
Gas Gathering Systems, Gas Plant, Sales
Compressor
Fuel
M
M
M
M
M
Gas Well
Gas Well
Gas well
Separator
Produced Water

Figure 4.2. CBM wells with meter at every well and minimal water

Calculate Actual Battery Water Production

Water disposition volume with inventory change is to be prorated back to the well level based on a battery-calculated water-gas ratio (WGR) applied to each well.

If water is recovered at a well during swabbing operations, that water is added to the well's production water volume calculated using the WGR for that well. The recovered water must also be added to the battery disposition. The swabbed water can be shipped to a disposal facility or to the battery water tank, but it must not be part of the battery WGR calculation, and it must be netted off if it is put into the battery water tank.

Calculate Actual Battery Gas Production

Total actual battery gas production is equal to total gas disposition plus fuel, flare, and vent volumes and is prorated back to each well using the gas proration factor based on the well test meter estimated volumes.

Scenario 2

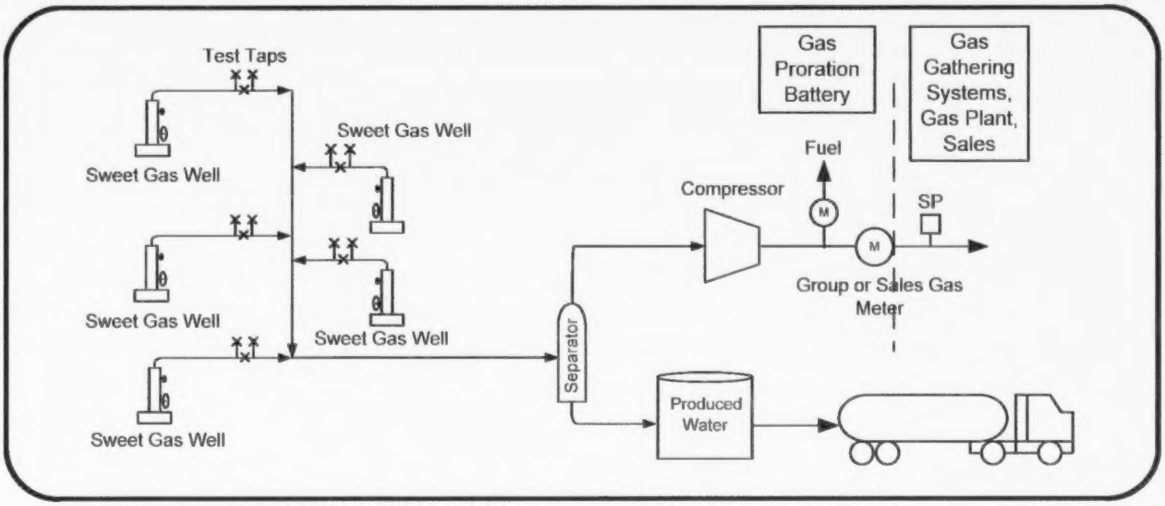

Test Taps
Sweet Gas Well
Sweet Gas Well
Sweet Gas Well
Sweet Gas Well
Sweet Gas Well
Sweet Gas Well
Separator
Compressor
Fuel
M
M
Gas Proration Battery
Gas Gathering Systems, Gas Plant, Sales
SP
Group or Sales Gas Meter
Produced Water

Figure 4.3. CBM with only test taps at wellhead and minimal water

Calculate Actual Battery Water Production

Water volumes to be prorated back to the well level are determined using water dispositions and inventory measurement based on a calculated battery WGR and estimated monthly gas production.

If water is recovered at a well during swabbing operations, that water is added to the produced water volume calculated using the WGR for that well. The recovered water should also be added to the battery disposition. The swabbed water can be shipped to a disposal facility or to the battery water tank, but it must not be part of the battery WGR calculation, and it must be netted off if it is put into the battery water tank.

Calculate Actual Battery Gas Production

Total gas production is equal to total gas disposition plus fuel, flare, and vent volumes and is to be prorated back to each well based on its well-test estimated volumes and the gas proration factor.

4.2.2.5 Gas Gathering System (PRA subtype: 621 and 622)

A facility consisting of pipelines used to move gas production from oil batteries, gas batteries, and/or other facilities to another facility (usually a gas plant) is considered to be a gas gathering system. It may include compressors, line heaters, dehydrators, and other equipment.

Inlet measurement usually consists of the battery or facility group measurement point.

Outlet measurement usually consists of the gas plant inlet measurement.

See Section 15.2.1.6 for water reporting requirements.

4.2.2.6 Gas Plant (PRA subtypes: 401 to 406)

A gas plant is a system or arrangement of equipment used for the extraction of H_2S, helium, ethane, NGLs, or other substances from raw gas. It does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/d of hydrocarbon liquids without using a liquid extraction process (e.g., refrigeration, desiccant). In addition, it does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of nonregenerative scavenging chemicals that generate no H_2S or sulphur dioxide (SO_2).

Each plant inlet stream must have inlet separation and continuous measurement for all liquids and gas before commingling with other streams and must be used to report volume on the PRA for the plant receipt from upstream facilities (except for gas group batteries) and for plant balance. However, there are situations where the raw gas has been stripped of its liquid (not recombined downstream) and measured upstream of the plant site. If all streams entering a gas plant on the same gas gathering system are "dry" (the absence of free liquids), the gas plant inlet measurement may consist of the gas gathering system outlet measurement or battery group measurement.

Measurement of all gas deliveries out of the gas plant, such as sales, lease fuel for other facilities, flare and vent gas, acid gas disposition, and any volumes used internally, is required unless otherwise exempted by the ERCB. Monthly liquid inventory change must be accounted for and reported to the PRA. (See Figure 4.4.)

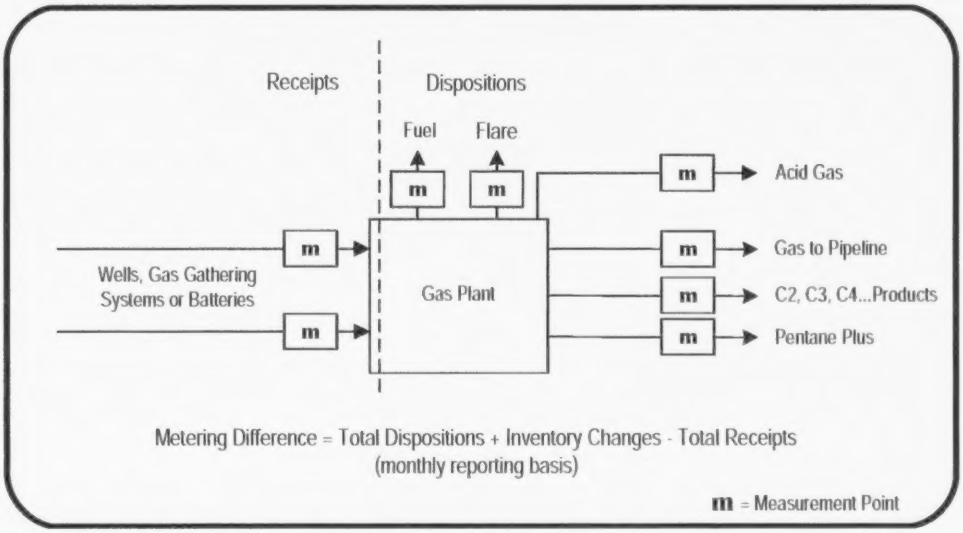

Receipts
Dispositions
Fuel
Flare
m
Acid Gas
Gas to Pipeline
C2, C3, C4...Products
Pentane Plus
Wells, Gas Gathering Systems or Batteries
Gas Plant
Metering Difference = Total Dispositions + Inventory Changes - Total Receipts (monthly reporting basis)
m = Measurement Point

Figure 4.4. Typical gas plant measurement and reporting points

Delineation for an Oil Battery Delivering To or Receiving From a Gas Plant on Same Site

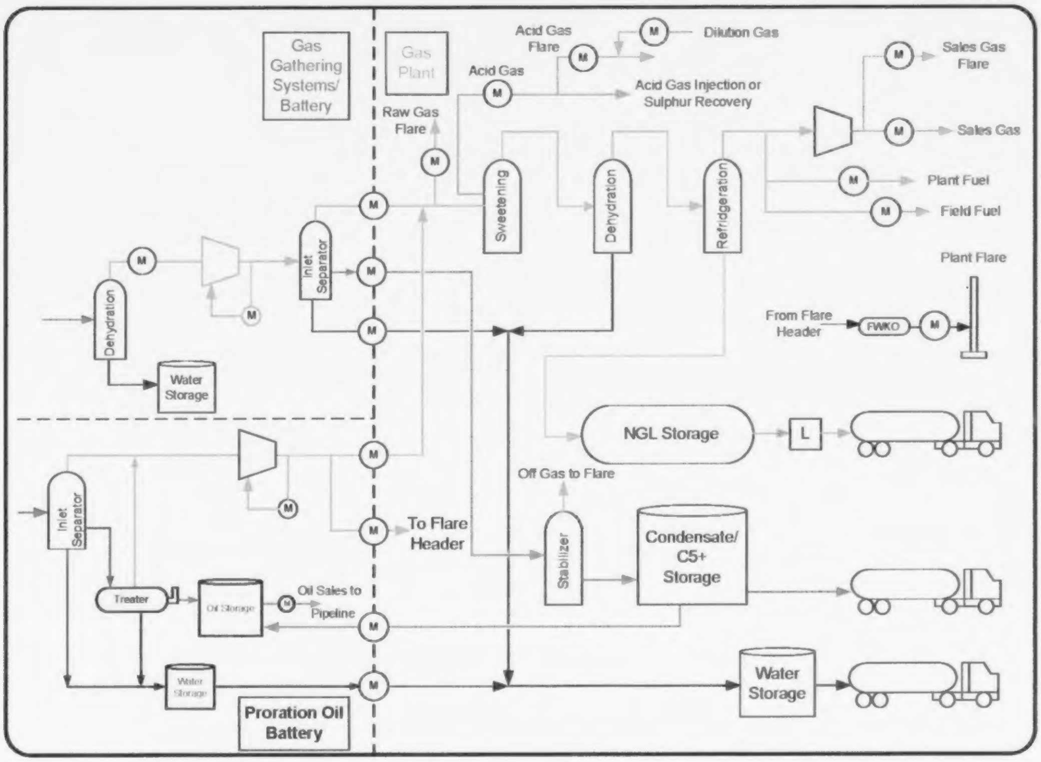

Gas Gathering Systems/ Battery
Gas Plant
Acid Gas Flare
Dilution Gas
Acid Gas
Acid Gas Injection or Sulphur Recovery
Sales Gas Flare
Sales Gas
Raw Gas Flare
Sweetening
Dehydration
Refrigeration
Plant Fuel
Field Fuel
Plant Flare
From Flare Header
FWKO
Dehydration
Inlet Separator
Water Storage
NGL Storage
L
Off Gas to Flare
Inlet Separator
To Flare Header
Stabilizer
Condensate/ C5+ Storage
Treater
Oil Storage
Oil Sales to Pipeline
Water Storage
Water Storage
Proration Oil Battery
M

Figure 4.5. Oil battery delivering to or receiving from a gas plant

Oil battery gas and water sent to a gas plant for further processing or disposition and gas for flaring must be measured and reported as disposition from the oil battery to the gas plant. The gas plant will report the receipts, total flare, and dispositions.

Gas plant condensate, C5+, and/or NGL sent to an oil battery must be measured and reported as disposition to the oil battery. This is a royalty trigger point requiring delivery point measurement.

4.2.2.7 Gas Fractionation Plant (PRA subtype: 407)

Condensate delivered to a gas fractionation plant licensed by the ERCB as a facility must be measured and reported in cubic metres by the operator of the fractionation facility as condensate received and reported, in accordance with existing ERCB requirements for trucked production.

4.3 Base Requirements for Gas Measurement

4.3.1 System Design and Installation of Measurement Devices

The design and installation of measurement systems must be in accordance with the following or as approved by Measurement Canada.

1) If an orifice meter system is used to measure gas, it must be designed and installed according to the applicable AGA Report #3: *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids* (AGA3) listed in Table 4.1 below.

Table 4.1. Orifice meters design requirement (see detailed explanation in this section)

Meter run date of manufacture	Applicable AGA3 (API MPMS 14.3, Part 2) version
Before February 2003	AGA3 1991 or earlier meter run with upstream and/or downstream ID marking – may be reused or relocated for its designed application except to replace a meter where AGA3 2000 spec is required. Non-AGA meter run or run not marked with upstream or downstream ID – grandfathered for the existing volumetric throughput application; if relocated, it must be refurbished to AGA3 (1985) or later specification but cannot be used for sales/delivery point measurement.
After January 2003 (except for sales/delivery point meters measuring sales specification processed gas)	February 1991 or April 2000
All sales/delivery point meters measuring sales specification processed gas manufactured after January 2003	April 2000

When a meter such as a gas plant outlet meter is used to check sales/delivery point (royalty trigger point) measurement and is not normally used to report volumes to the ERCB, it does not require AGA3 April 2000 specification. However, when another gas source ties in to the sales pipeline between the check meter and the sales/delivery point (royalty trigger point) meter, the check meter could be used to report volumes to the ERCB. In this case, the AGA3 April 2000 specification is required if the meter is manufactured after January 2003, as shown in Figures 4.6 and 4.7, and the operator cannot replace the existing meter run with another meter run manufactured before February 2003 unless it meets the AGA3 April 2000 specification.

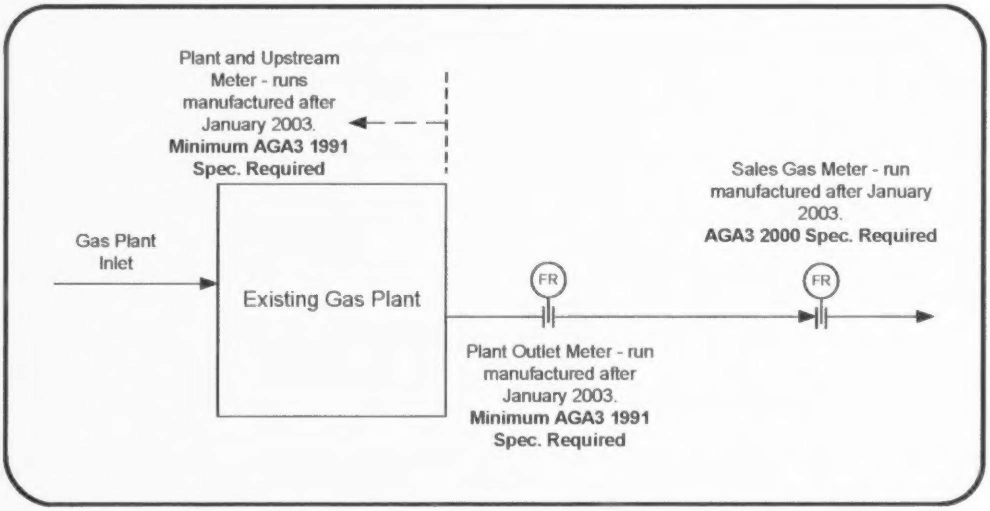

Plant and Upstream Meter - runs manufactured after January 2003.
Minimum AGA3 1991 Spec. Required
Sales Gas Meter - run manufactured after January 2003.
AGA3 2000 Spec. Required
Gas Plant Inlet
Existing Gas Plant
FR
FR
Plant Outlet Meter - run manufactured after January 2003.
Minimum AGA3 1991 Spec. Required

Figure 4.6

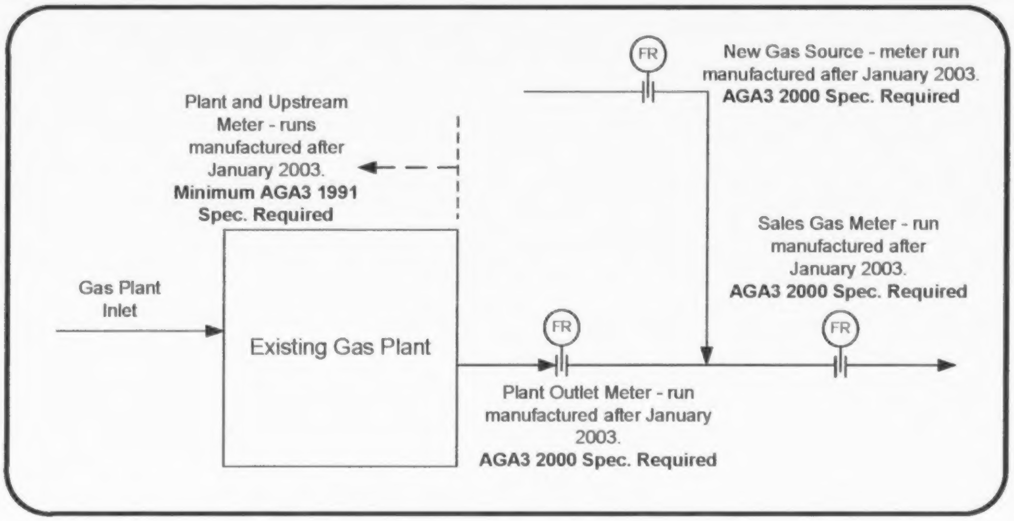

New Gas Source - meter run manufactured after January 2003. AGA3 2000 Spec. Required
Plant and Upstream Meter - runs manufactured after January 2003. Minimum AGA3 1991 Spec. Required
FR
Sales Gas Meter - run manufactured after January 2003. AGA3 2000 Spec. Required
Gas Plant Inlet
Existing Gas Plant
FR
FR
Plant Outlet Meter - run manufactured after January 2003. AGA3 2000 Spec. Required

Figure 4.7

A permanently marked plate with the following information must be attached to each meter run and maintained in readable condition (not painted over or covered with insulation, etc.) for inspection:

- manufacturer's name
- serial number
- date of manufacture
- average upstream inside diameter (ID) of the meter run at 25.4 mm upstream of the orifice plate in millimetres to one decimal place (or to three decimal places if indicated in inches)
- AGA3 version/year (for new runs only after January 31, 2005) and/or AGA3 configuration for runs manufactured after January 2003 and not using the April 2000 specification

Meter runs that are manufactured before February 2003 and designed to the AGA3 1991 or earlier specifications complete with the upstream and/or downstream ID markings may be relocated or reused for the application they are designed for.

For existing in-service meter runs that are manufactured before February 2003 and are not designed to the AGA3 2000 or earlier specifications at the time of manufacture or not marked with upstream or downstream ID, nominal pipe ID can be used for flow calculations. These meter runs are grandfathered for the existing volumetric throughput. If new gas volumes are added to such an existing meter run or if a meter run is to be relocated, it must be inspected or refurbished to ensure that it meets the minimum of AGA3 1985 specifications, but it must not be used for sales/delivery point (royalty trigger point) measurement.

The orifice plate must be permanently marked with the plate bore in millimetres to two decimal places (or to three decimal places if indicated in inches), preferably within **6 mm** of the outside edge of the plate, to avoid interfering with normal flow if the marking creates a dent or protrusion on the plate surface.

The chart drive for a circular chart recorder used to measure gas well gas production or group oil battery gas production must not be more than 8 days per cycle unless the exception criteria specified in Section 5: Site-specific Deviation from Base Requirements are met or ERCB site-specific approval is obtained. A 24-hour chart drive is required for test gas measurement associated with Class 1 and 2 proration oil wells. An 8-day chart drive may be used for test gas measurement associated with Class 3 and 4 proration oil wells. If the mode of operation causes painting on the chart because of cycling or on/off flows, a 24-hour chart is required for any gas measurement point or EFM must be used.

Temperature measurement must be installed according to AGA3 specifications and the temperature must be determined in accordance with item 10 below.

2) Linear metering systems, such as a turbine or vortex meter, used to measure gas must be designed and installed according to the provisions of the 1985 or later editions of the AGA Report #7: *Measurement of Gas by Turbine Meters* (AGA7) or the manufacturer's recommendation.

   Temperature measurement is to be installed according to AGA7 (i.e., between one and five pipe diameter downstream of the meter) or the meter manufacturer's recommendation and the temperature must be determined as per item 10 below.

   The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site (e.g., electronic correctors, EFM systems) or at a later date (e.g., pressure and temperature charts).

3) Rotary metering systems must be designed and installed according to the provisions of the 1992 or later edition of the ANSI B109.3: *Rotary Type Gas Displacement Meters* or the manufacturer's recommendation.

   Install pressure taps not more than 20 pipe diameters upstream and downstream of the meter, to allow for measuring pressure drop across the meter and determining if the meter is over-ranging, if required. It is acceptable for the tap openings to be present within the meter body. The upstream tap must be used for pressure measurement and must be reading the metering pressure (i.e., there must be no pressure restriction between the tap and the meter, such as a regulator).

   The meter must be equipped with a non-reset counter. This can be mechanical or electronic.

   Install temperature measurement according to the meter manufacturer's recommendation or less than 20 pipe diameters downstream of the meter, with no restrictions between the meter and the temperature probe. The temperature must be determined as per item 8 below.

   The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site (e.g., electronic correctors, EFM systems) or at a later date (e.g., pressure and temperature charts) unless the meter is operating under constant pressure, such as continuous fuel measurement downstream of a pressure regulating valve, in which case pressure and temperature correction factors at the determined operating temperature can be used for volumetric correction.

4) Diaphragm displacement metering systems must be designed and installed according to the provisions of the 1992 or later edition of the ANSI B109.1: *Diaphragm Type Gas*

Displacement Meters (up to 500 cubic feet/hour capacity), or ANSI B109.2: *Diaphragm Type Gas Displacement Meters (over 500 cubic feet/hour capacity)*, and/or the manufacturer's recommendation.

Other conditions are the same as for the rotary meter above.

5) Venturi or flow nozzle type of metering systems must be installed according to the provisions of the 1991 or later edition of the ISO Standard 5167: *Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full* (ISO 5167) or the meter manufacturer's recommendation. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site or at a later date.

6) Ultrasonic metering systems must be designed and installed according to the provisions of the 1998 or later editions of *AGA Report No. 9: Measurement of Gas by Multipath Ultrasonic Meters* (AGA9). The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections.

7) Coriolis mass metering systems must be designed and installed according to the provisions of the latest edition of *AGA Report No. 11: Measurement of Natural Gas by Coriolis Meter*. External gas sample analysis and density must be used to determine the gas volume at base conditions (see Section 4.3.2).

8) If metering systems other than those listed above, such as v-cones or wedge meters, are used to measure gas, they must be installed according to applicable industry accepted standards or the meter manufacturer's recommendation. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections (where required) either on site or at a later date.

9) Any electronic gas measurement system must be designed and installed according to the requirements stated in Section 4.3.6. Any EFM system designed and installed in accordance with API MPMS, Chapter 21.1, is considered to have met the audit trail and reporting requirements. However, the performance evaluation is still required in accordance with Section 4.3.6. All EFM devices must have a continuous temperature reading for flow calculation.

10) The flowing gas temperature must be measured and recorded according to Table 4.2.

Table 4.2. Temperature reading frequency table for gas measurement

Minimum temperature reading frequency	Criteria or events
Continuous	Sales/delivery points (royalty trigger point) and/or EFM devices
Daily	> 16.9 10^3 m^3/d
Weekly	≤ 16.9 10^3 m^3/d
Daily	a) Production (proration) volume testing, or b) Nonroutine or emergency flaring and venting

Note that the temperature-measuring element must be installed on the meter run if present or near the meter such that it will be sensing the flowing gas stream temperature. That is, the licensee cannot use the surface temperature of the piping or use a thermowell location where there is normally no flow. A meter equipped with a temperature compensation device is considered to have continuous temperature measurement.

11) Any measurement under vacuum conditions must have absolute pressure measurement to accurately measure the static pressure.

12) Mass meters that depend on gas density to determine the volume should only be used if

- the density does not change, or
- the effect of density change on the volume is within the uncertainty requirements for that application, or
- the density can be determined and recorded for flow calculation.

These meters are not recommended for use at gas plant flare stacks.

4.3.2 Volumetric Calculations

The gas volume calculations comply if the following requirements are met.

- If an orifice meter is used to measure gas, the licensee must use the 1985 or later editions of the AGA3 to calculate the gas volumes.
- If a positive displacement meter or a linear type of meter, such as a turbine, ultrasonic, or vortex meter, is used to measure gas, volumes must be calculated according to the provisions of the 1985 or later editions of the AGA7. Corrections for static pressure, temperature, and compressibility are required.
- If a venturi or flow nozzle type of meter is used to measure gas, volumes must be calculated according to the provisions of the 1991 or later edition of the ISO 5167 or the meter manufacturer's recommended calculation procedures.
- If a Coriolis mass meter is used to measure gas, volumes must be calculated from the measured mass flow and the base density derived from a representative gas sample analysis, including corrections for compressibility. The flowing density measured by the Coriolis mass meter is of insufficient accuracy in a gas application and must not be used to compute volumes.
- If meter types other than those listed above, such as v-cones or wedge meters, are used to measure gas, volumes must be calculated according to the applicable industry accepted standard or the meter manufacturer's recommendation.
- If condensate production from a gas well is required to be reported as a gas equivalent volume, the calculation of the gas equivalent factor must be performed in accordance with the methodologies outlined in Section 8.3. The following are the general requirements:
  - The gas equivalent volume (GEV) is to be determined based on the latest condensate sample analysis.
  - The gas equivalent volume can be determined using the volume fractions, mole fractions, or mass fractions of the condensate analysis.
  - The gas equivalent volume can be determined using all of the individual components in the condensate analysis, *or* the C_5 and/or heavier components in the sample can be grouped as C_{5+}, C_{6+}, C_{7+} or other heavier component groups. If the heavier components are grouped, the gas equivalent factor for the grouped components must be calculated using the molecular weight and/or relative density of the grouped components.

- Correction for deviation from the Ideal Gas Laws for compressibility is to be based on equations published in the November 1992, second edition of the AGA Transmission Measurement Committee Report No. 8 (AGA8): *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases* or one of the methods listed in the section below. For EFM systems installed before 1994 with software or hardware limitations incompatible with the second edition of AGA8, an earlier version can be used.

Compressibility Factors Used in Gas Volume Calculations

Produced or injected gas volume measurements must be corrected for pressure, temperature, gas composition, and the compressibility of the natural gas.

The AGA8[1] (1992) or Redlich-Kwong with Wichert-Aziz sour gas corrections method should be used for the calculation of the compressibility factors. However, other methods can also be used, provided that the licensee documents the reason for their use. Other methods that could be used are

- Pitzer et al. with Wichert-Aziz sour gas corrections
- Dranchuk, Purvis, Robinson with Wichert-Aziz sour gas corrections (Standing and Katz)
- Dranchuk, Abou-Kassam with Wichert-Aziz sour gas corrections (Starling)
- Hall, Yarborough with Wichert-Aziz sour gas corrections

The ERCB will also accept the use of methods other than those mentioned above. If others are used, a suitable reference and comparison to the AGA8 (1992) method or to experimental results and the justification for use must be documented and provided to the ERCB for inspection on request.

The AGA8 publication includes several approaches for estimating the properties of natural gas for use in the AGA8 calculation. The full compositional analysis (Detail) method must be used rather than the less accurate partial composition method.

If paper charts are used, the compressibility factor should be calculated at least once for each gas chart cycle. Flow computers and other EFM systems used for gas measurement must calculate and update the compressibility (or supercompressibility) factor at a minimum of once every five minutes, whenever the gas composition is updated, or whenever the average pressure or temperature changes by more than ± 0.5% from the previous average 5-minute value used for calculation.

Physical Properties of Natural Gas Components

The ERCB adopts the physical properties contained in the most recent edition of the Gas Processors Suppliers Association (GPSA) *SI Engineering Data Book*[1] or the Gas Processors Association (GPA) *2145*[1] publication, whichever is the most current. The licensee must ensure that it is using the up-to-date list and, if necessary, update its data. If an EFM system does not have the capability to accept updated physical constants, then the existing set of physical constants may be used; however, that type of EFM system must not be used for measurement of processed gas that meets sales specifications. For standards, such as AGA8, that have imbedded physical constants different in value from those in GPA 2145 or GPSA *SI Engineering Data Book*, changes to such standards are not required unless they are made by the standard association.

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[1] See Section 4.4: References for complete bibliographical details for these citations.

4.3.3 Production Data Verification and Audit Trail

4.3.3.1 General

The field data, records, and any calculations or estimations including EFM relating to ERCB-required production data submitted to the PRA must be kept for inspection on request. The reported data verification and audit trails must be in accordance with the following:

1) When a bypass around a meter is opened or when, for any reason, gas does not reach the meter or the recording device, a reasonable estimate of the unmetered volume must be determined, the method used to determine the estimate must be documented, and a record of the event must be made.

2) A record must be maintained that identifies the gas stream being metered, the measurement devices, and all measurements, inputs, times, and events related to the determination of gas volumes. (See Section 4.3.4: Operations for more detail on orifice chart recorders.) If EFM is used, the required data must be collected and retained according to Section 4.3.6.

3) Test records: Any documentation produced in the testing or operation of metering equipment that affects measured volumes. This includes the record containing volume verification and calibration measurements for all secondary and tertiary devices.

4) When a gas metering error is discovered, the licensee of the facility must immediately correct the cause of the error and submit amended monthly production reports to the PRA to correct all affected gas volumes.

5) All flared and vented gas must be reported as described in ERCB *Directive 007: Volumetric and Infrastructure requirements*. Incinerated gas must be reported as "flared" gas if an incinerator is used in place of a flare stack. This would not apply to acid gas streams at a gas plant that are incinerated as part of normal operations; in such cases, the incinerated acid gas would be reported as shrinkage, not as flared.

6) Whenever possible, the licensee must report gas as fuel, flared, or vented as occurring at the location where the fuel use, flaring, or venting took place. This will allow industry and ERCB staff to match flaring or venting that is observed in the field with that reported. When the fuel usage, flaring, or venting location is within a gas gathering system but is not at a licensed entity,
    a) it should be reported as an activity associated with the closest licensed facility (e.g., compressor) within the gas gathering system, or
    b) if there is no applicable licensed facility within the gas gathering system, it should be reported as an activity associated with the gas gathering system itself.

7) Licensees must not prorate or allocate flared and vented volumes that occur at a facility to other upstream facilities and/or well locations.

8) Dilution gas, purge gas, or gas used to maintain a minimum heating value of the flared or incinerated gas is to be reported as fuel. The reported total flare volume must exclude any of these fuel volumes.

9) Production hours for gas wells designed to operate on an on/off cycle basis, such as intermittent timers, pump-off controls, plunger lifts, manual on/off, or pumpjacks, that

are "operating normally and as designed on repeated cycles" and where part of the operation involves shutdown of pump equipment and/or shut-in as part of the repeated cycles are to be considered on production even when the wells are not flowing. At least one on/off cycle must be completed within a reporting period. Physical well shut-ins (not as part of a repeated cycle) and emergency shutdowns (ESDs) are considered down time. The operation personnel have to make a decision based on the operating environment in other situations where the wells are not shut in but may or may not have production.

10) All gas usage, such as for instrumentation, pumps, purging, and heating, must be reported as fuel use on a per-site basis, even if it is vented afterwards. The volume must be measured on a per site basis if over 0.5 10^3 m^3/d or may be estimated if not over 0.5 10^3 m^3/d (see Figure 1.11). If there are multiple reporting facilities on the same site, the fuel use has to be separately reported to each individual facility and there must be overall site fuel measurement. The only exception is for integrated OWMF with WP, CT, and IF facilities on the same site, in which case fuel REC is to be reported at the ABWP and total OWMF fuel use at the same facility.

4.3.3.2 Gas Lift Systems for Both Oil and Gas Wells

There are four gas source scenarios, and each one may be subject to different measurement, reporting, and sampling and analysis requirements when gas is injected into the wellbore to assist in lifting the liquids to the surface. The *Directive 007* requirement is to update/change the well to "GAS LIFT" status for all wells that use gas lift.

Scenario 1

There is no external gas source for the lift gas used; the raw gas is being separated and recirculated continuously at the well site with compressor(s). Regular sampling and analysis frequency for the well type applies (see Section 8.4).

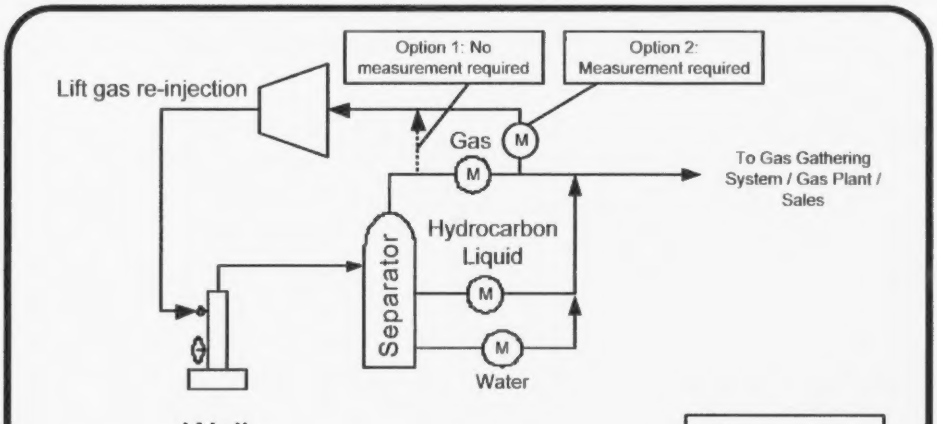
Option 1: No measurement required
Option 2: Measurement required
Lift gas re-injection
Gas
M
M
To Gas Gathering System / Gas Plant / Sales
Hydrocarbon Liquid
Separator
M
M
Water
Well
Scenario 1

Figure 4.8. Lift gas from existing well – scenario 1

Option 1: If the lift gas is taken from upstream of the production measurement point, then there is no reporting requirement.

Option 2: If the lift gas is taken from downstream of the production measurement point, then measurement of the lift gas is required and the total well gas production will be the difference between the total measured production volume and the measured lift gas volume.

Scenario 2

The lift gas is received back from a downstream gas plant/facility that is classified as "return gas" (no royalty implications).

Measurement is required at the battery level for any gas coming back from the gas plant/facility after sweetening/processing and reported as "REC." Part of this return gas could be used for fuel at the well. The lift gas injected into the wellbore must be measured and regular sampling and analysis frequency for the well type applies (see Section 8.4).

There are two possibilities under scenario 2 (see below).

For proration tested wells, the gas lift volume during the test period must be netted off the total test gas production volume to determine the estimated gas production volume for each well.

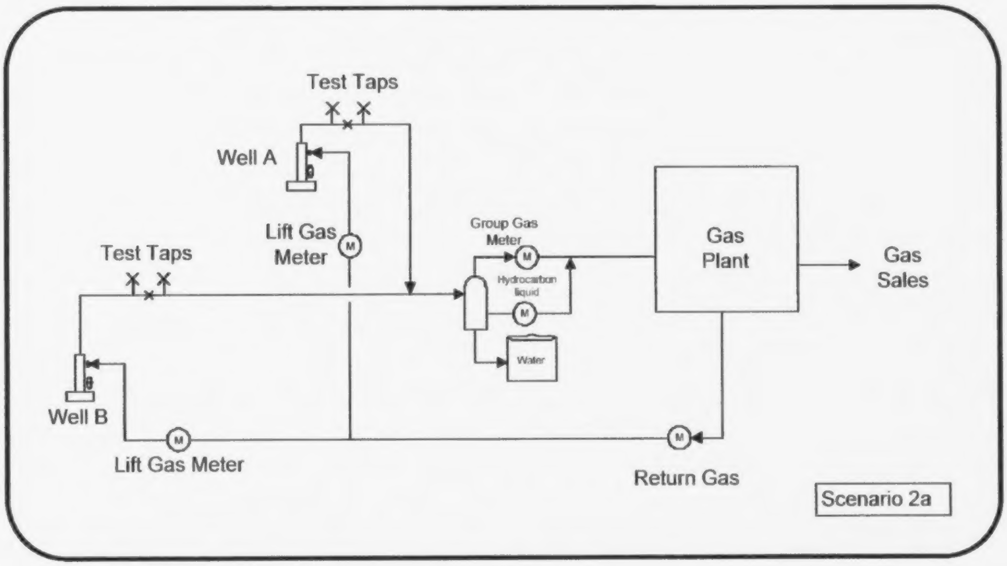
Test Taps
Well A
Lift Gas Meter
Test Taps
Group Gas Meter
Hydrocarbon liquid
Water
Gas Plant
Gas Sales
Well B
Lift Gas Meter
Return Gas
Scenario 2a

Figure 4.9. Lift gas using return gas from plant – scenario 2a

For continuously measured wells, the gas lift volume must be netted off the total measured gas production volume to determine the actual gas production volume for each well.

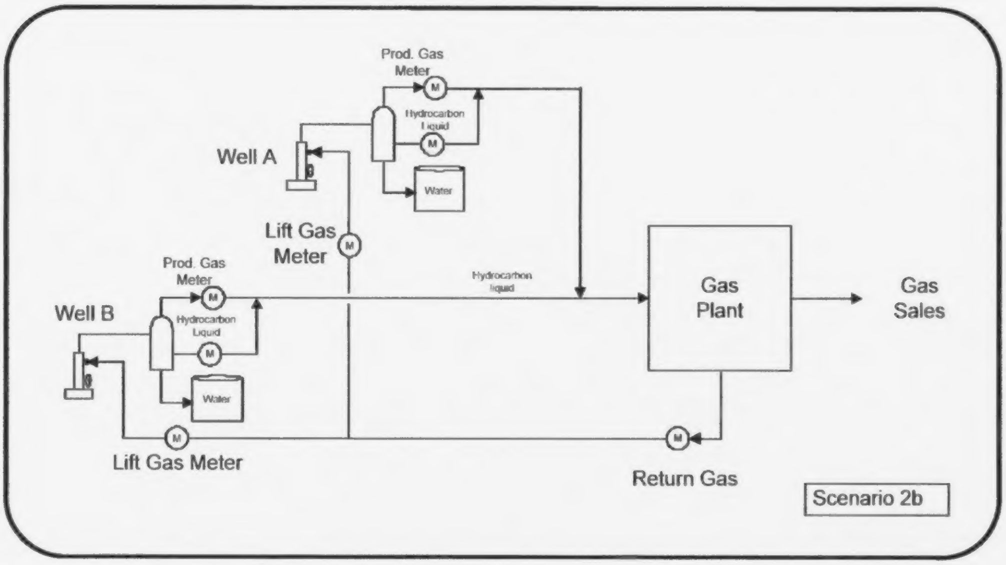
Prod. Gas Meter
M
Hydrocarbon Liquid
M
Well A
Water
Lift Gas Meter
M
Prod. Gas Meter
M
Hydrocarbon liquid
Gas Plant
Gas Sales
Well B
Hydrocarbon Liquid
M
Water
M
Lift Gas Meter
M
Return Gas
Scenario 2b

Figure 4.10. Lift gas using return gas from plant – scenario 2b

Scenario 3

The lift gas comes from external sources with royalty implications.

Any gas coming from a non-royalty paid gas source must be measured and reported at the battery/facility level as "PURREC" and as "PURDISP" at the sending facility. The well measurement and reporting requirement is the same as scenario 2 above and the gas sampling and analysis frequency for this type of gas lift well is semiannual.

Scenario 4

The lift gas comes from royalty exempted sources, such as TCPL or ATCO Gas.

The measurement and reporting requirement is the same as scenario 2 with the additional requirement that prior approval must be obtained from Alberta Energy to use the royalty-paid stream ID# WG999999 for the SAF/OAF submission to identify royalty-exempted gas that is to be used as gas lift.

The gas sampling and analysis frequency for this type of gas lift well is semiannual.

4.3.4 Operations—Base Requirements for Acceptable Gas Measurement and Reading of Gas Charts

4.3.4.1 General Operations

- **Accounting meters using differential pressure sensing devices must be equipped with full port valves at the metering tap on the sensing lines. The valves must be the same size as the sensing lines (12.7 mm minimum for meter runs 102 mm in diameter or larger, and 9.5 mm minimum for meter runs less than 102 mm). All metering design and installation** must ensure that the sensing line diameter does not change from the sensing tap valve to the manifold for delivery point, group point, and sales point measurement.

- Sharing of metering taps by multiple differential pressure devices is not allowed if it will cause increased measurement uncertainty, such as painting or spiking charts, or under pulsation conditions.
- A separate set of valve manifolds must be used for each device.
- The orifice meter must be in good operating condition.
- Chart recorders, sensing lines, and other piping must be in good operating condition and suitably winterized to prevent them from freezing and disrupting measurement. The exception is clean dry sales specification gas with minimal moisture, which is acceptable not to winterize.
- Sensing lines must be self-draining towards the sensing taps to prevent liquid from being trapped in the line and disrupting measurement accuracy from **February 2, 2009, onward** if they do not meet the exception criteria for changes in sensing line diameter below.

4.3.4.1(a) Exceptions

Sensing Line Tap Valves and Changes in Sensing Line Diameter

Grandfathering of existing differential pressure-sensing tap valves for installation before May 7, 2007, is granted without application **unless**

- the metering device is being upgraded, refurbished, and commissioned within a new application or relocated, or
- the metering device does not meet the single point uncertainty limit, as detailed in Section 1: Standards of Accuracy, or
- the metering point is subject to noticeable pulsation effects, such as physical vibration or audible flow noise, or is downstream of a reciprocal compressor on the same site, or
- the metering point is at a delivery point, group point, sales point (royalty trigger point), or custody transfer point.

Grandfathering of changes in sensing line diameter from the sensing tap to the manifold, such as drip pots, installed **before February 2, 2009,** is granted without application **unless**

- the metering device does not meet the single point uncertainty limit, as detailed in Section 1: Standards of Accuracy, or
- the metering point is subject to noticeable pulsation effects, such as physical vibration or audible flow noise, or is downstream of a reciprocal compressor on the same site, or
- the metering point is at a delivery point, group point, sales point (royalty trigger point), or custody transfer point, or
- the fuel measurement point has a clean, dry fuel source at a facility, such as a gas plant.

If the current metering installation does not meet the grandfathering requirement, operators must make any necessary changes required to bring the installation into compliance with this section within one year of **February 2, 2009.**

4.3.4.2 Chart Operations

Field operation personnel **must** ensure that

- the meter location is properly identified on the chart;
- the chart is correctly dated;
- the on and off chart times are recorded on the chart to the nearest quarter hour if not actual;
- the correct orifice plate and line size are recorded on the chart;
- the time (to the nearest quarter hour) of any orifice plate change is indicated on the chart, along with the new orifice plate size;
- it is noted on the charts if the differential, pressure, or temperature range of the recorder has been changed or if they are different from the ranges printed on the chart;
- a copy of the chart calibration report is kept on site or readily available for on-site inspection if it is a manned facility;
- the flowing gas temperature is recorded on the chart in accordance with Table 4.2 above;
- proper chart reading instructions are provided when the pen fails to record because of sensing line freezing, clock stoppage, pens out of ink, overlapping traces, or other reasons (draw in the estimated traces, request to read as average flow for the missing period, or provide estimate of the differential and static); and
- any data or traces that require correction must not be covered over or obscured by any means.

Field operation personnel **should** ensure that

- a notation is made on the chart with regard to whether or not the meter is set up for atmospheric pressure (for square root charts);
- the accuracy of the meter clock speed is checked and the chart reader is instructed accordingly of any deviations;
- the differential pen is zeroed once per chart cycle;
- differential pen recordings are at 33% or more within the chart range whenever possible;
- static pen recordings are at 20% or more within the chart range whenever possible;
- when there is a painted differential band, instructions are provided as to where it should be read; there are various ways to read a painted chart:
    - if the differential pen normally records at the top of the painted band but spikes quickly down and up during separator dump cycles, it is reasonable to read the differential near the top of the band (or vice versa);
    - if the differential pen is in constant up and down motion, it is reasonable to read the differential at the root mean square (RMS) of the band or in a sine wave motion alternating between the top and bottom of the painted area;
- the pen trace colours conform to the industry-accepted practice (RED for differential, BLUE for static, and GREEN for temperature); however, any colour may be used, provided the colour used is documented.

4.3.4.3 ERCB Site-Specific Requests

If an inspection of a measurement device or of procedures reveals unsatisfactory conditions that significantly reduce measurement accuracy, the ERCB inspector or auditor will direct in writing that the licensee implement changes to improve measurement accuracy, and this direction will become a condition of operation for that facility or facilities. Examples of conditions applicable to orifice chart recorders are as follows:

- thick pen traces that will cause excessive error when reading the traces
- painting traces
- differential or static pens recording too low on the chart—in some cases, this cannot be avoided because of low flow rate, high shut-in pressure, and equipment or operating pressure range limitations.

4.3.4.4 Chart Reading

The chart integrator/planimeter operator **must** ensure the following:

- Visible gaps between the integrator/planimeter traces and chart traces are minimized.
- The counter is read correctly.
- The integrator is calibrated periodically and after each change of pens.
- The correct integrator or square root planimeter constants are noted.
- The correct integrator setback is recorded.
- The correct coefficient, using all of the required factors, is recorded.

4.3.4.5 Alternative Chart Reading Technology

The base requirements for alternative methods developed to read orifice meter charts, other than conventional manual methods (planimeters, integrators), is as follows. An example of such technology is the use of digital scanning technology to scan and store an image of the chart and the use of computer programs to read and interpret the digital image of the chart and the pen traces.

The use of alternative technologies to read charts does not require prior approval of the ERCB, but the licensee using any new technology must be able to demonstrate that the following requirements are met:

- The equipment and/or procedures used to read the chart must not alter or destroy the chart such that it cannot subsequently be read using conventional equipment and/or procedures.
- The accuracy and repeatability of the new equipment and/or procedures must be equal to or better than conventional equipment and/or procedures.

The following requirements are specific to the use of digital scanning technology for reading charts:

1) The original chart must be retained for at least 12 months (18 months for gas production associated with heavy oil or crude bitumen), or alternatively the licensee may choose the following procedure for audit trail:

  a) An original scanned image of the chart (both front and back) must be stored so that it cannot be changed. If the chart back is blank, the back does not need to be scanned provided there is a statement entered in the record to that effect. There must be a method to confirm that a set of front and back scans belong to the same chart if scanned and stored. No alteration or editing of the original scanned image is allowed.

  b) At least two separate electronic copies of the scanned images must be retained and one copy must be stored off site at a different physical address/location for the applicable required period.

Note that although the ERCB accepts the above electronic submission for audits, other jurisdiction might not. Therefore the original chart should be kept for other jurisdictional audits.

2) Editing or alterations may only be made to a copy of the original scanned image of the chart. If the edited version is used for accounting purposes, the edited or altered image must be stored for the applicable required period and in the same manner as in item 1 above.

3) An image of the chart showing how the chart pen traces were read or interpreted must be stored for the applicable required period and in the same manner as in item 1 above.

4) The requirements and recommendations in Section 4.3.4 of this directive must be adhered to. If there are any changes or additions to those requirements and recommendations specific to chart scanning, these must be documented and made available for instructing chart analysts. An additional requirement specific to chart scanning is as follows:

   - When a differential pen is not zeroed correctly, the zero line must be adjusted to the correct position if it is obvious on the chart (such as when the zeroing was out when changing charts but the pen was not adjusted) and/or as documented by the operator. Other situations will require the judgement of the chart analyst and confirmation from the facility operator. Any zero adjustment must only reposition the zero line and must maintain the entire span of the pen. (The distance between the actual zero and the pen trace must not be altered.)

5) For ERCB inspection/audit purposes, the licensee must upon request

   - submit any original paper charts or the scanned original images or make them available for on-line viewing, and
   - submit all edited images or make them available for on-line viewing.

Note that the software used to open the scanned images should be readily and freely available on the market. In case there is any specific/proprietary image reader software required to view the scanned and stored chart images, it must also be submitted.

6) Upon request, the repeatability of the scanning technology must be demonstrated by performing three consecutive scans with a rotation of the chart image of about 120° before each scan and integrations of the same chart image. The calculated volumes from each reading must be within ± 0.5% of the average of the three scans and integrations.

7) The ERCB may check the accuracy of the chart-reading technology and volume calculations by providing charts with known calculated volumes. The volumes

determined by the chart reading technology must be within ± 0.5% of the ERCB's known values.

4.3.5 Exceptions

4.3.5.1 Gas in Solution with Oil Volumes under Pressure

In some cases a gas volume must be determined where the gas is dissolved in an oil volume under pressure, and there is no opportunity to measure the gas volume prior to it being commingled with other gas volumes. In that case, the gas volume may be determined by estimation, regardless of its daily volume rate. An example of such a gas volume is the gas held in solution with oil volumes leaving a test separator at an oil proration battery, where the test oil volumes are combined with production from other wells downstream of the test separator. The purpose of estimating the gas in solution is to determine the total gas produced by a well during a production test, since the gas volume measured by the test gas meter will not include the gas that is still in solution with the test oil volume.

A single gas-in-solution (GIS) factor may be determined and used to estimate the gas volume held in solution with the oil stream for each oil stream where the production sources (producing formation) are the same and test separator operating conditions are similar. Additional GIS factors are required for wells in the battery that produce from different formations and where other test separators operate at different pressure and/or temperature conditions. Licensees should also consider determining seasonal GIS factors where ambient temperature differences may significantly affect the factors or when operating conditions change significantly.

The GIS factor may be determined by one of the following applicable tests/procedures:

- A 24-hour test may be conducted such that the production from a well (or group of wells) is directed through the test and group separation/treating equipment, with all other wells shut in or directed around the equipment. The total volume of gas released from the oil after it leaves the test separator must be measured; this volume divided by the stock tank volume of oil determined at the test separator provides a GIS factor.

- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a pressure-volume-temperature (PVT) analysis can be conducted. The analysis must be based on the actual pressure and temperature conditions that the oil sample would be subjected to downstream of the sample point, including multiple stage flashing. The GIS factor is calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.

- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional analysis can be conducted. A computer simulation program may be used to determine the GIS factor based on the compositional analysis.

- A "rule of thumb" estimate (0.0257 m^3 of gas/m^3 of oil/kPa of pressure drop) may be used as the GIS factor for conventional light-medium oil production until a more accurate, specific GIS factor is determined. It may be used on a continuous basis, without the need for determining a more accurate GIS factor, if well oil production rates do not exceed 2 m^3/d or if all battery gas production is vented or flared.

- Other methods listed in the Canadian Association of Petroleum Producers (CAPP) *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities* may be used.

4.3.5.2 Gas Produced in Association with Conventional Oil Well and Gas Well Production

If a gas stream volume associated with conventional oil well or gas well production does not exceed 0.5 10^3 m^3 per day at any given measurement/disposition point, the volume may be determined by estimation instead of measurement. No specific approval is required, but the operator must keep the estimation/testing documentation for ERCB audit. Examples of the gas streams that may be estimated if the daily volume limitation is not exceeded include well test gas, battery group gas, single-well battery gas, fuel gas used on a per site basis, and oil/condensate tank vented gas. A gas stream that must be measured regardless of daily volume is dilution gas added to an acid gas stream to ensure complete combustion (due to the importance of accurately determining those volumes).

Initial qualification of gas streams where volumes may be estimated can be based on existing historical data or determined by conducting one of the applicable tests/procedures in Section 4.3.5.4. Qualifying gas volumes may be estimated by using a gas-oil-ratio (GOR) factor if gas volume estimates will vary in conjunction with oil volumes or by using an hourly rate if gas volumes are not dependent upon oil volumes. These factors must be updated annually to confirm continuing eligibility for estimation and to update the factors used to estimate gas volumes. The factors must also be updated immediately following any operational changes that could cause the factors to change. Licensees should also consider determining seasonal GOR factors if ambient temperature differences may significantly affect the factors. Updated factors may be determined by one of the applicable tests/procedures described below.

4.3.5.3 Gas Produced in Association with Heavy Crude Oil/Crude Bitumen Production

See Section 12.3.2 for details.

4.3.5.4 Methods for Determining Factors/Rates Used in Estimating Gas Volumes

If gas volumes will be estimated using a GOR:

- A 24-hour test may be conducted such that all the applicable gas and oil volumes produced during the test are measured (including vented gas). The gas volume is to be divided by the oil volume to result in the GOR factor.

- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a PVT analysis can be conducted. The analysis must be based on the actual pressure and temperature conditions the oil sample would be subjected to downstream of the sample point. The GOR factor will be calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.

- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional analysis can be conducted. A computer simulation program may be used to determine the GOR based on the compositional analysis.

- Other methods listed under the Canadian Association of Petroleum Producers (CAPP) *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities* may be used

If gas volumes will be estimated using an hourly rate:

- A meter may be used to measure the gas stream for a minimum of one hour. The gas volume measured during this test may be used to determine the hourly rate that will be used to estimate gas volumes.
- If applicable, such as for fuel gas volumes, the hourly rate may be determined based on the equipment manufacturer's stated gas consumption rates and the actual operating conditions.

Example Calculations for Estimating Gas Volumes Using GOR and GIS Factors

Determination of Total Produced Gas for a Single-Well Oil Battery

Figure 4.11 depicts a single-well battery where a three-phase separator is used to separate oil, gas, and water production from a well. The oil in the separator is under pressure until it is directed to the storage tank, which is at atmospheric pressure (zero kPa gauge). When the oil pressure drops at the tank, the GIS within the oil will be released. The gas leaving the separator in this example is measured, while the GIS released at the tank is estimated using a GOR factor. Total gas production from the well is determined by adding the measured gas and the GIS released at the oil storage tank.

If a single-well battery uses a two-phase separator, the procedure for determining total gas production is the same as for a three-phase separator.

If the gas production rate meets the qualifying criteria for estimation and all production from the well produces directly to a tank without using a separator, the total gas production may be determined by using only a GOR factor.

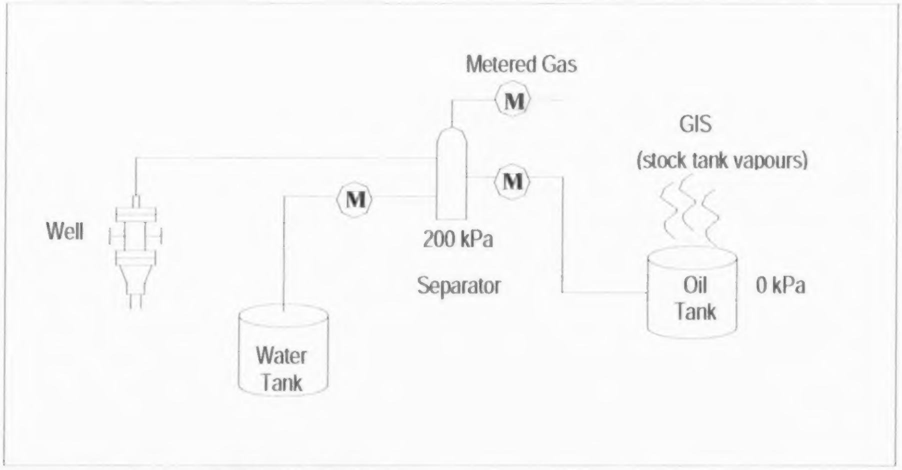

Figure 4.11. Single-well oil battery example

Sample Calculation: Total Gas Volume at a Single-Well Battery (Figure 4.11)

Monthly well data (hypothetical) given for this example:

Gas meter volume = 96.3 10^3 m^3 (from chart readings)

Oil meter volume = 643.3 m^3 (from meter or tank gauging)

Pressure drop = 200 kPa

GOR factor = 6.37 m^3 gas/m^3 oil or 0.03185 m^3 gas/m^3 oil/kPa pressure drop (determined using a method other than the "rule of thumb")

Step 1: Calculate GIS volume:

6.37 m^3/m^3 x 643.3 m^3 = 4097.8 m^3 = 4.10 10^3 m^3
or

0.03185 m^3/m^3/kPa x 643.3 m^3 x 200 kPa = 4097.8 m^3 = 4.10 10^3 m^3

Step 2: Calculate the total battery gas production for the month:

96.3 10^3 m^3 + 4.1 10^3 m^3 = 100.4 10^3 m^3

Note that total reported battery gas production is to be rounded to one decimal place.

Determination of Total Produced Gas for an Oil Proration Battery

Figure 4.12 depicts a multiwell oil proration battery where production testing of individual wells is done by directing individual well production through a test separator at the main battery site or through a test separator at a satellite facility located away from the main battery site.

In this example, the oil, gas, and water leaving the test separator at the satellite are recombined with the satellite group production and directed to the group separation and measurement equipment at the main battery site. The oil and water leaving the test separator at the main battery site are recombined with the battery group production, but the gas leaving the test separator recombines with the group gas downstream of the group gas measurement point. The oil in the group separator is under pressure until it is directed to the storage tank, which is at atmospheric pressure (zero kPa gauge). When the oil pressure drops at the tank, the GIS with the oil will be released.

The total gas production at the battery will be the sum of all the measured test gas at the battery site, the measured group gas at the battery, and the GIS released at the oil storage tank.

Trucked oil volumes received at the battery must not be included with the total battery oil volume when determining the GIS released at the oil storage tank.

At some facilities a vapour recovery unit (VRU) may be installed to collect any GIS that may be released at the oil storage tank. If the VRU is equipped with a meter or the recovered gas is directed through the group gas meter, a GIS calculation will not be required because the measured VRU gas will either be added to or included in the other measured gas volumes.

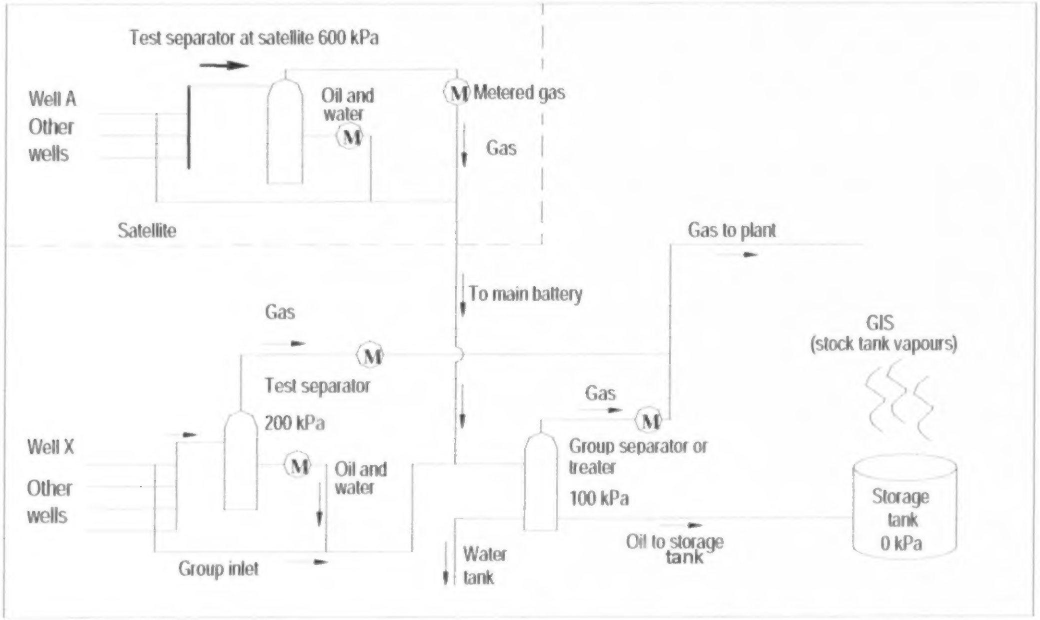
Test separator at satellite 600 kPa
Well A
Other
wells
Oil and
water
M
M
Metered gas
Gas
Satellite
Gas to plant
To main battery
Gas
M
GIS
(stock tank vapours)
Test separator
200 kPa
Gas
M
Well X
Other
wells
M
Oil and
water
Group separator or
treater
100 kPa
Storage
tank
0 kPa
Water
tank
Oil to storage
tank
Group inlet

Figure 4.12. Multiwell oil battery example

Sample Calculation: Total Gas Production at the Oil Proration Battery (Figure 4.12)

Monthly battery data (hypothetical) given for this example:

Oil production at the proration battery = 745.0 m^3 for the month (from meter and/or tank gauging)

Total test gas measured at the battery site = 30.0 $10^3 m^3$ (from chart readings)

Measured group gas production = 67.4 $10^3 m^3$ (from chart readings)

Pressure drop from the group vessel to oil storage tank = 100 kPa

GOR factor = 3.99 m^3 gas /m^3 oil or 0.0399 m^3/m^3/kPa (determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume:

$3.99\ m^3/m^3 \times 745.0\ m^3 = 2972.6\ m^3 = 2.97\ 10^3\ m^3$

or

$0.0399\ m^3/m^3/kPa \times 745\ m^3 \times 100\ kPa = 2972.6\ m^3 = 2.97\ 10^3\ m^3$

Step 2: Calculate the total produced gas volume for the battery:

$67.4\ 10^3\ m^3 + 30.0\ 10^3\ m^3 + 2.97\ 10^3\ m^3 = 100.4\ 10^3\ m^3$

Note that total reported battery gas production is to be rounded to one decimal place.

Determination of Individual Well Test Gas for an Oil Proration Battery

Figure 4.12 depicts a multiwell oil proration battery where production testing of individual wells is done by directing individual well production through a test separator at the main battery site or through a test separator at a satellite facility located away from the main battery site. In either case, the oil leaving the test separator is under pressure and will be subjected to two stages of pressure drop—one at the group separator and one at the storage tank. The total gas produced by a well during a test will be the sum of the gas measured as it leaves the test separator and the GIS that will evolve from the test oil volume after leaving the test separator. In the example, the test separators at the battery and satellite operate at significantly different pressures, and the oil leaving the test separator at the satellite will contain more GIS than the oil leaving the test separator at the battery.

Sample Calculation: Test Gas Production for Wells in the Satellite (Figure 4.5)

Satellite test data (hypothetical) given for this example for well "A":

Measured test oil = 7.22 m^3 (from oil meter)

Measured test gas = 1.27 $10^3 m^3$ (from chart readings)

GIS factor = 25.62 m^3 gas/m^3 oil or 0.0427 m^3 gas/m^3 oil/kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 600 kPa to group pressure at 100 kPa to oil storage tank pressure at atmospheric pressure or zero kPa gauge, determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume:

$0.0427\ m^3/m^3/kPa \times 7.22\ m^3 \times 600\ kPa = 185.0\ m^3 = 0.19\ 10^3\ m^3$

or

$25.62\ m^3/m^3 \times 7.22\ m^3 = 185.0\ m^3 = 0.19\ 10^3\ m^3$

Step 2: Calculate the total test gas produced for well "A" for this test:

$1.27\ 10^3\ m^3 + 0.19\ 10^3\ m^3 = 1.46\ 10^3\ m^3$

Note that test gas volumes must be determined to two decimal places (in $10^3\ m^3$).

Sample Calculation: Test Gas Production for Wells in the Battery (Figure 4.5)

Battery test data (hypothetical) given for this example for well "X":

Measured test oil = 3.85 m^3 (from oil meter)

Measured test gas = 2.33 $10^3 m^3$ (from chart readings)

GIS factor = 7.90 m^3 gas/m^3 oil or 0.0395 m^3 gas/m^3 oil/kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 200 kPa to group pressure at 100 kPa to oil storage tank pressure at atmospheric pressure or zero kPa gauge, determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume:

$0.0395\ m^3/m^3/kPa \times 3.85\ m^3 \times 200\ kPa = 30.4\ m^3 = 0.03\ 10^3\ m^3$

or

$7.90\ m^3/m^3 \times 3.85\ m^3 = 30.4\ m^3 = 0.03\ 10^3\ m^3$

Step 2: Calculate the total test gas produced for well "X" for this test:

$2.33\ 10^3\ m^3 + 0.03\ 10^3\ m^3 = 2.36\ 10^3\ m^3$

Note that test gas volumes must be determined to two decimal places (in $10^3\ m^3$).

4.3.6 Electronic Flow Measurement (EFM) for Gas

An EFM system is defined as any flow measurement and related system that collects data and performs flow calculations electronically. If it is part of a Distributed Control System (DCS), Supervisory Control and Data Acquisition system (SCADA) or Programmable Logic Controller system (PLC), only the EFM portion has to meet the requirements in this section. All EFM systems approved under *Guide 34* may continue as approved.

The following systems are not defined as an EFM:

- any meter with an electronic totalizer or pulse counter that does not perform flow calculations (with or without built-in temperature compensation)
- a Remote Terminal Unit (RTU) that transmits any data other than flow data and does not calculate flow

4.3.6.1 Base Requirements for EFM

If an EFM is used to calculate volumes for ERCB accounting purpose, the licensee must be able to verify that it is performing within the ERCB target limits defined in this section.

When any parameter that affects the flow calculation is changed, such as orifice plate size, meter factor, fluid analysis, or transmitter range, a signoff procedure or an event log must be set up to ensure that the change is made in the EFM system. All data and reports must be retained for a minimum of 12 months.

Hardware and software requirements:

- The EFM data storage capability must exceed the time period used for data transfer from the EFM system.
- The EFM system must be provided with the capability to retain data in the event of a power failure (e.g., battery backup, UPS, EPROM).
- System access must have appropriate levels of security, with the highest level of access restricted to authorized personnel.
- The EFM system must be set to alarm on out-of-range inputs, such as temperature, pressure, differential pressure (if applicable), flow, low power, and communication failures.
- Any EFM configuration changes or forced inputs that affect measurement computations must be documented either electronically via audit trails or on paper.

The values calculated from forced data must be identified as such.

4.3.6.2 Performance Evaluation

A performance evaluation test must be completed within **two weeks** after the EFM is put into service and **immediately** after any change to the computer program or algorithms that affects the flow calculation; it must be documented for ERCB audit on request. For existing EFM systems, the ERCB encourages licensees to conduct their own performance evaluations. A performance evaluation must be conducted and submitted for ERCB audit on request. The ERCB considers either one of the following methods acceptable for performance evaluation:

1) Conduct a performance evaluation test on the system by inputting known values of flow parameters into the EFM to verify the volume calculation, coefficient factors, and other parameters. The first **seven** test cases included in this section are for gas orifice meters

(AGA3 flow calculations), each with different flow conditions and gas properties. **Test Case 8** is for the AGA7 flow calculation for positive displacement or linear meters. Other manufacturers' recommended equations can also be used to evaluate the EFM performance. The seven AGA3 test cases could also be used to evaluate any compressibility or supercompressibility factors used in other flow calculations using the same gas composition, pressure, and temperature in the calculation as inputs.

2) Evaluate the EFM calculation accuracy with a flow calculation checking program that performs within the target limits for all the factors and parameters listed in the test cases below. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information is to be taken from the EFM and input into the checking program. If the instantaneous EFM flow parameters, factors, and flow rates are not updated simultaneously, multiple snapshots may have to be taken to provide a representative evaluation.

Note that some DCS or other control systems have built-in and/or manual input of pressure and temperature for flow calculations. Since the pressure and temperature are not continuously updated, they are not acceptable for ERCB accounting and reporting purposes unless ERCB approval is obtained.

The volumetric flow rate (Q) obtained from a performance evaluation test must agree to within ± 0.25% of those recorded on the sample test cases or other flow calculation checking programs. If the ± 0.25% limit is exceeded, the EFM must be subjected to a detailed review of the calculation algorithm to resolve the deviation problem. For gas orifice meters, if no AGA3 factor or parameter outputs are available, the acceptable volumetric gas flow rate limit is lowered to ± 0.15%.

Test Cases 1 to 7 for Verification of Orifice Meter Gas Flow Calculation Programs

The ERCB has developed test cases to verify that the EFM system correctly calculates gas flow rates from orifice meters. The seven test cases were calculated on the following basis:

- They are for flange taps only.
- The atmospheric pressure is assumed to be 93.08 kPa(a) (13.5 psia).
- The heaviest carbon component was assumed to be normal heptane.
- The ideal gas relative density was converted to the real gas relative density.
- The same static pressure value is used for pressure taps that are located upstream (U/S) or downstream (D/S) of the orifice plate.
- The AGA3 (1985) results were calculated based on upstream conditions (for both upstream and downstream static pressure tap) in imperial units (the Y_2 factor is also provided for reference). The metric conversion factor for the calculated gas volume is 0.02831685. The compressibility factors were calculated using the Redlich-Kwong (RK) equation with the Wichert-Aziz correction for sour gas.
- The AGA3 (1990) results were calculated using the Detail AGA8 (1992) compressibility factor calculation and using the upstream expansion factor Y_1, as recommended by the AGA3 (1990), Part 1, Section 1.8, even though the pressure tap may be downstream of the orifice plate. (The Y_2 factor is also provided for reference when applicable.)

- The orifice plate material is assumed to be 316 stainless steel and the meter run to be carbon steel at reference temperature of 20°C, isentropic exponent (k) = 1.3, viscosity = 0.010268 centipoise.
- The base conditions (101.325 kPa[abs] and 15°C) are used in the calculated temperature base factor (F_{tb}) and pressure base factor (F_{pb})

Test Case 8 for Verification of AGA7 Gas Flow Calculation Programs

The ERCB has developed a test case to verify that the EFM system correctly calculates gas flow rates using the AGA7 equations. The test case was calculated on the following basis:

- The heaviest carbon component was assumed to be normal heptane.
- The compressibility factors were calculated using the Detail AGA8 (1992) or the Redlich-Kwong (RK) equation with the Wichert-Aziz correction for sour gas.

Table 4.3. Allowable deviation limits for the AGA3 (1985) equation

AGA3 (1985) factors	Allowed deviation limit from test cases
Y, F_a, F_r, and F_{tf}	± 0.01%
F_b	± 0.1%
F_{gr}, F_{pv}	± 0.2%
Q	± 0.25% or ± 0.15% without the above factors

Table 4.4. Allowable deviation limits for the AGA3 (1990) equation

AGA3 (1990) factors	Allowed deviation limit from test cases
Y_1, and E_v	± 0.01%
C_d and Z_b	± 0.1%
Z_f	± 0.2%
Q	± 0.25% or ± 0.15% without the above factors

Table 4.5. Allowable deviation limits for the AGA7 equation

AGA7 factors	Allowed deviation limit from test cases
F_{pm} (flowing pressure) and F_{tm} (flowing temperature)	± 0.1%
S (compressibility)	± 0.2%
Q	± 0.25% or ± 0.15% without the above factors

TEST CASE 1 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0184	iC_4	-	0.0081
CO_2	-	0.0000	nC_4	-	0.0190
H_2S	-	0.0260	iC_5	-	0.0038
C_1	-	0.7068	nC_5	-	0.0043
C_2	-	0.1414	C_6	-	0.0026
C_3	-	0.0674	C_7	-	0.0022

Ideal gas relative density - 0.7792

Meter Data (flange taps)

Meter run I.D. - 52.370 mm (2.0618 inches)
Orifice I.D. - 9.525 mm (0.375 inches)

Flow Data (24 hr)

Static pressure - 2818.09 kPa(a) (408.73 psia)
Differential pressure - 10.2000 kPa (40.9897 inches H_2O)
Flowing temperature - 57.0°C (134.600°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	28.4286	28.4286
Y_1	0.9989	0.9989
Y_2	N/A	1.0007
F_{tb}	0.9981	0.9981
F_{gr}	1.1308	1.1308
F_a	1.0012	1.0012
F_r	1.0006	1.0006
F_{pb}	1.0023	1.0023
F_{tf}	0.9351	0.9351
F_{pv}	1.0360	1.0361
C'	31.175	31.179
Q	2.7422	2.7475 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.5990	0.5990
Y_1	0.9989	0.9989
Y_2	N/A	1.0007
E_v	1.0005	1.0005
Z_b	0.9959	0.9959
Z_f	0.9280	0.9277
Q	2.7478	2.7531 10^3 m^3/24 hr

TEST CASE 2 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0156
CO_2 - 0.0216
H_2S - 0.1166
C_1 - 0.7334
C_2 - 0.0697
C_3 - 0.0228

iC_4 - 0.0044
nC_4 - 0.0075
iC_5 - 0.0028
nC_5 - 0.0024
C_6 - 0.0017
C_7 - 0.0015

Ideal gas relative density - 0.7456

Meter Data (flange taps)

Meter run I.D. - 102.26 mm (4.026 inches)
Orifice I.D. - 47.625 mm (1.875 inches)

Flow Data (24 hr)

Static pressure - 9100.94 kPa(a) (1319.98 psia)
Differential pressure - 11.0000 kPa (44.2046 inches H_2O)
Flowing temperature - 50.0°C (122.0°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	733.697	733.697
Y_1	0.9996	0.9996
Y_2	N/A	1.0002
F_{tb}	0.9981	0.9981
F_{gr}	1.1564	1.1564
F_a	1.0010	1.0010
F_r	1.0002	1.0002
F_{pb}	1.0023	1.0023
F_{tf}	0.9452	0.9452
F_{pv}	1.1072	1.1073
C'	888.905	889.000
Q	145.93	146.03 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6019	0.6019
Y_1	0.9996	0.9996
Y_2	N/A	1.0003
E_v	1.0244	1.0244
Z_b	0.9967	0.9967
Z_f	0.8098	0.8097
Q	146.08	146.18 10^3 m^3/24 hr

TEST CASE 3 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0500	iC_4	-	0.0000
CO_2	-	0.1000	nC_4	-	0.0000
H_2S	-	0.2000	iC_5	-	0.0000
C_1	-	0.6000	nC_5	-	0.0000
C_2	-	0.0500	C_6	-	0.0000
C_3	-	0.0000	C_7	-	0.0000

Ideal gas relative density - 0.8199

Meter Data (flange taps)

Meter run I.D. - 590.55 mm (23.250 inches)
Orifice I.D. - 304.80 mm (12.000 inches)

Flow Data (24 hr)

Static pressure - 10342.14 kPa(a) (1500.00 psia)
Differential pressure - 22.1600 kPa (89.0522 inches H_2O)
Flowing temperature - 60.0°C (140.0°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	30429.66	30429.66	
Y_1	0.9993	0.9993	
Y_2	N/A	1.0004	
F_{tb}	0.9981	0.9981	
F_{gr}	1.1028	1.1028	
F_a	1.0013	1.0013	
F_r	1.0001	1.0001	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9309	0.9309	
F_{pv}	1.1076	1.1078	
C'	34636.6	34643.21	
Q	8603.19	8614.04	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6029	0.6029	
Y_1	0.9993	0.9993	
Y_2	N/A	1.0004	
E_v	1.0375	1.0375	
Z_b	0.9968	0.9968	
Z_f	0.8216	0.8213	
Q	8564.77	8575.48	10^3 m^3/24 hr

TEST CASE 4 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0029
CO_2 - 0.0258
H_2S - 0.0000
C_1 - 0.9709
C_2 - 0.0003
C_3 - 0.0001

iC_4 - 0.0000
nC_4 - 0.0000
iC_5 - 0.0000
nC_5 - 0.0000
C_6 - 0.0000
C_7 - 0.0000

Ideal gas relative density - 0.5803

Meter Data (flange taps)

Meter run I.D. - 146.36 mm (5.7622 inches)
Orifice I.D. - 88.900 mm (3.500 inches)

Flow Data (24 hr)

Static pressure - 9839.99 kPa(a) (1427.17 psia)
Differential pressure - 6.6130 kPa (26.575 inches H_2O)
Flowing temperature - 22.35°C (72.23°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	2694.965	2694.97	
Y_1	0.9998	0.9998	
Y_2	N/A	1.0001	
F_{tb}	0.9981	0.9981	
F_{gr}	1.3116	1.3116	
F_a	1.0001	1.0001	
F_r	1.0002	1.0002	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9884	0.9884	
F_{pv}	1.0843	1.0843	
C'	3790.16	3790.31	
Q	501.64	501.82	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6047	0.6047	
Y_1	0.9998	0.9998	
Y_2	N/A	1.0001	
E_v	1.0759	1.0759	
Z_b	0.9980	0.9980	
Z_f	0.8425	0.8425	
Q	503.44	503.63	10^3 m^3/24 hr

TEST CASE 5 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0235
CO_2 - 0.0082
H_2S - 0.0021
C_1 - 0.7358
C_2 - 0.1296
C_3 - 0.0664
iC_4 - 0.0088
nC_4 - 0.0169
iC_5 - 0.0035
nC_5 - 0.0031
C_6 - 0.0014
C_7 - 0.0007

Ideal gas relative density - 0.7555

Meter Data (flange taps)

Meter run I.D. - 154.05 mm (6.0650 inches)
Orifice I.D. - 95.250 mm (3.750 inches)

Flow Data (24 hr)

Static pressure - 2499.9 kPa(a) (362.58 psia)
Differential pressure - 75.000 kPa (301.395 inches H_2O)
Flowing temperature - 34.0°C (93.2°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	3111.24	3111.24
Y_1	0.9894	0.9897
Y_2	N/A	1.0044
F_{tb}	0.9981	0.9981
F_{gr}	1.1485	1.1485
F_a	1.0005	1.0005
F_r	1.0001	1.0001
F_{pb}	1.0023	1.0023
F_{tf}	0.9695	0.9695
F_{pv}	1.0382	1.0394
C'	3561.90	3567.34
Q	800.22	813.37 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6042	0.6041
Y_1	0.9894	0.9897
Y_2	N/A	1.0044
E_v	1.0822	1.0822
Z_b	0.9962	0.9962
Z_f	0.9240	0.9217
Q	799.83	813.00 10^3 m^3/24 hr

TEST CASE 6 (for AGA3 Flow Calculations)

Gas Analysis

N_2	- 0.0268		iC_4	-	0.0123
CO_2	- 0.0030		nC_4	-	0.0274
H_2S	- 0.0000		iC_5	-	0.0000
C_1	- 0.6668		nC_5	-	0.0000
C_2	- 0.1434		C_6	-	0.0180
C_3	- 0.1023		C_7	-	0.0000

Ideal gas relative density - 0.8377

Meter Data (flange taps)

Meter run	I.D.	-	52.500 mm (2.0669 inches)
Orifice	I.D.	-	19.050 mm (0.750 inches)

Flow Data (24 hr)

Static pressure	-	2506.33 kPa(a) (363.50 psia)
Differential pressure	-	17.0500 kPa (68.5171 inches H_2O)
Flowing temperature	-	7.2°C (44.96°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	115.138	115.138
Y_1	0.9978	0.9978
Y_2	N/A	1.0012
F_{tb}	0.9981	0.9981
F_{gr}	1.0902	1.0902
F_a	0.9996	0.9996
F_r	1.0003	1.0003
F_{pb}	1.0023	1.0023
F_{tf}	1.0148	1.0148
F_{pv}	1.0708	1.0714
C'	136.15	136.22
Q	14.602	14.660 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6005	0.6005
Y_1	0.9978	0.9978
Y_2	N/A	1.0012
E_v	1.0088	1.0088
Z_b	0.9951	0.9951
Z_f	0.8588	0.8578
Q	14.687	14.746 10^3 m^3/24 hr

TEST CASE 7 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0070
CO_2 - 0.0400
H_2S - 0.0000
C_1 - 0.8720
C_2 - 0.0340
C_3 - 0.0250

iC_4 - 0.0062
nC - 0.0090
iC_5 - 0.0052
nC_5 - 0.0016
C_6 - 0.0000
C_7 - 0.0000

Ideal gas relative density - 0.6714

Meter Data (flange taps)

Meter run I.D. - 52.500 mm (2.0669 inches)
Orifice I.D. - 12.70 mm (0.50 inches)

Flow Data (24 hr)
Static pressure - 299.92 kPa(a) (43.50 psia)
Differential pressure - 6.3455 kPa (25.5 inches H_2O)
Flowing temperature - 1.67°C (35°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	50.523	50.523
Y_1	0.9933	0.9935
Y_2	N/A	1.0039
F_{tb}	0.9981	0.9981
F_{gr}	1.2190	1.2190
F_a	0.9994	0.9994
F_r	1.0018	1.0018
F_{pb}	1.0023	1.0023
F_{tf}	1.0250	1.0250
F_{pv}	1.0035	1.0036
C'	63.013	63.029
Q	1.4263	1.4416 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6006	0.6006
Y_1	0.9933	0.9934
Y_2	N/A	1.0039
E_v	1.0017	1.0017
Z_b	0.9973	0.9973
Z_f	0.9905	0.9903
Q	1.4335	1.4489 10^3 m^3/24 hr

TEST CASE 8 (for AGA7 Flow Calculations)

Gas Analysis

N_2	-	0.0268	iC_4	-	0.0123
CO_2	-	0.0030	nC_4	-	0.0274
H_2S	-	0.0000	iC_5	-	0.0000
C_1	-	0.6668	nC_5	-	0.0000
C_2	-	0.1434	C_6	-	0.0180
C_3	-	0.1023	C_7	-	0.0000

Flow Data (24 hr)

Uncorrected volume - 128.0 $10^3 m^3$

Static pressure - 2506.33 kPa(a) (363.50 psia)

Flowing temperature - 7.2°C (44.96°F)

Gas Volume Result

AGA7 (Volumetric Flow)

Factors

F_{pm}	24.6784
F_{pb}	1.0023
F_{tm}	1.0298
F_{tb}	0.9981

Using AGA8 compressibility equations,

S	1.1588
Q	3770.9 $10^3 m^3$/24 hr

Using RK compressibility equations,

S	1.1467
Q	3731.6 $10^3 m^3$/24 hr

EFM Reports

The required information on each report must be stored using electronic/magnetic (not necessarily on the EFM) or printed media and can exist individually on different formats or reports and generated on demand for audit, as follows:

- **Daily** for daily report required data
- **Monthly** for monthly report required data
- Event and alarm logs at regular intervals before information is overwritten
- Meter reports generated on request for audit

The Daily Report

The daily report must include

- meter identification
- daily accumulated flow, with indicating flags for estimated flows made by the system or by the operation personnel and alarms that have occurred for over-ranging of end devices
- hours on production or hours of flow (specify)
- flow data audit trail – include at least one of the following:
  - instantaneous values for flow rate, differential pressure (if applicable), static pressure, and temperature taken at the same time each day, or
  - average daily values for differential pressure (if applicable), static pressure, and temperature, or
  - hourly accumulated flow rate and average hourly values for differential pressure (if applicable), static pressure, and temperature

Existing EFM systems that predate *Guide 34* approvals and do not have any of the above audit trail capabilities, and cannot develop the capability due to system limitations, should be evaluated for upgrading, especially when new production is tied into the facilities. The ERCB may request upgrades, where audit/inspection results indicate they are warranted.

The Monthly Report

This report is for the entire system, providing data for each measurement point. It is to contain the following at each measurement point as applicable:

- monthly cumulative flow
- flags indicating any change made to flow volumes
- total hours on production or hours of flow (specify)

The Meter Report

The meter report details the configuration of each meter and flow calculation information. These values are used as part of the "audit trail" to confirm that the flow calculation is functioning correctly. Without them there is no way of verifying the accuracy of the system. The meter report must include the following as applicable and be produced on demand:

1) Instantaneous flow data
    - Instantaneous flow rate

- Instantaneous static pressure
- Instantaneous differential pressure
- Instantaneous flowing temperature
- Instantaneous relative density (if live)
- Instantaneous compressibility (if live)
- Instantaneous gas component (if live)
- Optional: instantaneous (AGA3) factors (see the orifice meter test cases above for output information)

2) Current configuration information for differential meters or other types of meters, whichever are applicable:
    - meter identification
    - date and time
    - contract hour
    - atmospheric pressure
    - pressure base (unless fixed)
    - temperature base (unless fixed)
    - meter tube reference inside diameter
    - orifice plate reference bore size
    - static pressure tap location
    - orifice plate material
    - meter tube material
    - calibrated static pressure range
    - calibrated differential pressure range
    - calibrated temperature range
    - high/low differential cutoff
    - relative density (if not live)
    - compressibility (if not live)
    - gas components (if not live)
    - meter factor and/or k factor
    - effluent correction factor

The Event Log

This log is used to note and record exceptions and changes to the flow parameter, configuration, programming, and database affecting flow calculations, such as, but not limited to,

- orifice size change
- transmitter range change

- date of gas/liquid analysis update
- algorithm changes
- meter factor, k factor, or effluent correction factor changes
- other manual inputs

The Alarm Log

The alarm log includes any alarms that may have an effect on the measurement accuracy of the system. The time of each alarm condition and the time of clearing of each alarm must be recorded. Alarms to be reported must include, but are not limited to,

- master terminal unit failures
- remote terminal unit failures
- communication failures
- low-power warning
- high differential pressure (for differential measurement devices)
- high/low volumetric flow rate (for other types of measurement)
- over-ranging of end devices

4.4 References

American Gas Association Transmission Measurement Committee Report No. 8 (AGA8), November 1992. *Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases.*

Dranchuk, P.M., and Abou-Kassam, J.H., "Calculation of Z Factors for Natural Gases Using Equations of State," *The Journal of Canadian Petroleum Technology*, Vol. 14, No. 3, July-September 1975, pp. 34-36.

Dranchuk, P.M., Purvis, R.A., and Robinson, D.B., "Computer Calculation of Natural Gas Compressibility Factors Using the Standing and Katz Correlation," *Institute of Petroleum Technical Series No. 1*, IP 74-008, 1974.

Gas Processors Association, *GPA 2145:* "Table of Physical Constants for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry."

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Hall, K.R., and Yarborough, L., "A New Equation of State for Z Factor Calculations," *The Oil and Gas Journal*, June 18, 1973, pp. 82-92.

Pitzer, K.S., Lippman, D.Z., Curl, R.F., Huggins, C.M., and Petersen, D.E., "The Volumetric and Thermodynamic Properties of Fluids II. Compressibility Factor, Vapour Pressure and Entropy of Vapourization," *Journal of the American Chemical Society*, Vol. 77, No. 13, July 1955.

Redlich, O., and Kwong, J.N.S., "On the Thermodynamics of Solutions. V. An Equation of State. Fugacities of Gaseous Solutions," *Chemical Review* 44, 1949, pp. 233-244.

Wichert, E., and Aziz, K., "Calculate Z's for Sour Gases," *Hydrocarbon Processing*, Vol. 51, May 1972, pp. 119-122.

Yarborough, L., and Hall, K.R., "How to Solve Equation of State for Z-Factors," *The Oil and Gas Journal*, February 18, 1974, pp. 86-88.

5 Site-specific Deviation from Base Requirements

Section 1: Standards of Accuracy states that a licensee may deviate from the ERCB's minimum measurement, accounting, and reporting requirements without specific approval if no royalty, equity, or reservoir engineering concerns are associated with the volumes being measured and the licensee is able to demonstrate that the alternative measurement equipment and/or procedures will provide measurement accuracy within the applicable uncertainties. This section describes situations where a licensee may deviate from the minimum requirements without ERCB approval, provided that specific criteria are met. Licensees may also apply for approval to deviate from the minimum requirements if the specific criteria are not met; this section indicates what information must be included in such an application. If these exceptions or approvals are in use, ERCB inspectors and auditors will review the licensee's records for demonstrated compliance with the criteria specified in this section or in the applicable approval.

Specialized Terminology Defined

Common Ownership	All wells in a battery belong to the same working interest participant, or if there is more than one working interest participant, each working interest participant has the same percentage interest in each well in the battery.
Common Crown or Freehold Royalty	When all the wells in a battery are produced under Crown mineral leases, the Crown receives the same royalty rate for each well, or when under leases granted by one Freehold mineral holder, the Freehold mineral holder receives the same royalty rate for each well. If there is more than one Freehold mineral holder for the wells in a battery, the total royalty rate for each well is the same.
Measured Gas Source(s)	These are single-phase measured gas source(s) downstream of separation and removal of liquids. This also includes the gas equivalent volume (GEV) of measured condensate if the condensate is recombined with the gas downstream of the separator.
Measured Oil	Oil is measured using equipment and/or procedures meeting delivery point measurement uncertainty limits. For emulsion, the delivery point measurement uncertainty limits apply to the total volume determination only.

5.1 Site-specific Exceptions

Deviation from base measurement, accounting, and reporting requirements is allowed without submission of an application to the ERCB, provided that all the initial qualifying criteria listed under the subsequent "Exception" sections are met.

Initial Qualifying Criteria—These criteria (detailed in subsequent sections) must be met to qualify for the exception. If the initial qualifying criteria have been met and the exception is implemented, it may remain in place indefinitely, as long as it does not meet any of the revocation clauses and no physical additions to the facility are made (e.g., new wells or zones). If additions or changes are made to the battery or facility, the initial qualifying criteria must be met for all the wells or zones added to the battery or facility for the exception to remain in place. If the licensee anticipates that physical additions may not meet the initial qualifying criteria, the licensee may reconfigure the facility to meet base measurement, accounting, and reporting requirements or submit an application for site-specific approval of deviation from the base requirements. Approval must be in place prior to implementation. Submission of an application does not guarantee that an approval will be granted.

Documentation Requirement—The licensee must retain the data and documentation to support the initial qualifying criteria and the last three testing records (if applicable) for as long as the exception is in place. The ERCB may revoke an exception if an audit or inspection reveals a lack of adequate supporting data or documentation. If the licensee cannot provide documentation requested for ERCB audit within 30 days, the licensee will be required to meet applicable ERCB base measurement requirements immediately. Alternatively, at the ERCB's discretion, the licensee may propose a plan to comply with the ERCB exception requirements within an ERCB-approved time period.

5.2 Site-specific Approval Applications

If the exception criteria cannot be met or if a specific situation is not covered in this section, the licensee may be allowed to deviate from base measurement, accounting, and reporting requirements upon approval of an application submitted to the ERCB Production Operations Section.

Approvals will remain in place indefinitely, including after transfer of the facility to another licensee, provided that conditions specified in the approval are met. If an ERCB audit or inspection finds that approval conditions are not being met, the approval may be revoked and the licensee may be required to meet applicable base requirements immediately, or other appropriate requirements may be specified.

If a licensee anticipates that proposed changes to the facility may not meet the approval conditions, the licensee may reconfigure the facility to meet base measurement, accounting, and reporting requirements or submit a new application for site-specific approval of deviation from the base requirements. Approval must be in place prior to implementation. Submission of an application does not guarantee that an approval will be granted.

The following information is required for all applications for site-specific deviation from base requirements. Other specific information that may be required is described in the following appropriate sections.

1) Well and/or facility list, including
   - battery code and locations
   - well locations (UID)
   - licence number(s)
   - respective pool/zone designations and unique identifier for each zone
   - indication as to unit or non-unit operation, if applicable
   - royalty status (Freehold/Crown, new/old, etc.)
   - equity (ownership) issues, if any
   - latest 6 months' gas, oil/condensate, and water flow rates (or expected flow rates for new wells)
   - up-to-date measurement schematic(s) for the existing system(s) and the proposed new gas or oil source(s), including all tie-in locations, if applicable

- facility plot plan for the existing system and the proposed new gas or oil source(s), if applicable

2) Justifications for deviation from measurement requirements (e.g., economics, minimal impact on measurement accuracy)

5.3 Chart Cycles Extended Beyond the Required Time Period

Chart cycle is the time required for a circular chart to complete one 360° revolution. An extension of the required chart cycle time may be applicable under the following scenarios:

- the gas well orifice meter chart cycle is greater than 8 days;
- the single-well oil battery orifice gas meter chart cycle is greater than 24 hours; or
- the Class 3 and 4 oil well test orifice gas meter chart cycle is greater than 8 days.

Mixing of wells with EFM systems and wells using extended cycle paper charts within the same battery is allowed without approval from the ERCB.

Group, sales, or delivery point meters and Class 1 and 2 oil well test gas meters do not qualify for exception for chart cycle extension, and approvals for extension of the chart cycle for those meters will not normally be granted.

5.3.1 Exceptions

Orifice meter gas chart cycles may be extended without ERCB site-specific approval if all the initial qualifying criteria below are met and no application is required.

Initial Qualifying Criteria

1) In the case of gas well measurement, all wells in the multiwell battery are gas wells. A single-well battery does not qualify for this exception on its own; the entire group battery or gas gathering system must be considered.

2) In the case of oil well measurement, all wells in the battery are oil wells, and the well produces either to a single-well battery or to a multiwell oil group where each well has its own separation and measurement equipment.

3) All wells are subjected to the same type of measurement (all well production is separated and all components are measured, or all well production is subject to effluent measurement) and the same chart cycle.

4) All wells flowing to the battery have common ownership and either common Crown or Freehold royalty, or

   - if there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received;
   - if there are no common Crown or Freehold royalties and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the licensee must apply to the ERCB for approval.

5) The monthly average volumetric gas flow rate for each well is ≤ 16.9 10^3 m^3/d (including the gas equivalent of condensate in the case of gas well measurement).

6) The differential pen records at 33% or more within the chart range, and the static pressure pen should record at 20% or more within the chart range (if possible). Painted traces must not exceed 4% of the differential pressure or static pressure range. Painting occurs when there are quick up and down movements of the pen, so that there is no visible separation between the up and down traces for a period of time.

7) Temperature must be recorded at a minimum of once per week, and if that is not possible, continuous temperature measurement (temperature pen) is required.

8) **The** wells that are within the same battery of the extended chart cycle wells and **are designed for** and/or operate on **on/off flows (e.g., plunger lifts, pump-off controls, intermittent timers) must be measured using** EFM. In addition, an extended chart cycle with EFM is allowed.

Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) Oil well/battery gas is added to a gas battery.

2) There is mixed measurement within the battery other than with EFM.

3) The oil well is not produced either to a single-well battery or to a multiwell oil group where each well has its own separation and measurement equipment.

4) The working interest participants for any well flowing to the battery have changed and a new working interest participant objects to the exception.

5) Any well within the battery has exceeded the 16.9 10^3 m^3/d monthly average actual gas production rate (including gas equivalent of condensate for gas wells).

6) Painted traces for any well exceeded 4% of the differential pressure range or the static pressure range.

7) A new well with on/off flows is added to an effluent proration battery, or one or more of the existing wells has been modified to operate on on/off flows but EFM is not used.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.3.2 Applications

The following information must be submitted with an application to extend orifice meter gas chart cycles if the above criteria are not met:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) if there are no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received;

3) a discussion of the impact on measurement accuracy of intermingling base chart cycles and extended chart cycles in a common battery, and how it may relate to concerns about working interest equity and/or royalty considerations;

4) a minimum of two current, consecutive, representative gas charts—Additionally, the licensee has the option to run the charts on the proposed chart cycle to gather test data for submission and then revert back to the required chart cycle after a maximum test period of 31 days. The original copies of any such charts created must be submitted with the application. The trial run must be clearly identified on the charts.

5.3.3 Considerations for Site-specific Approval

1) Differential and static pressures are stable, with essentially uninterrupted flow:

   - On/off flow as designed, including plunger lifts, pump-off controls, intermittent timers, etc., that cause painting or spiking, do not normally qualify for chart cycle extension.
   - The effects of painting are minimized. The amount of painting that is acceptable is decided case by case.
   - The differential pen should record at 33% or more within the chart range and the static pressure pen should record at 20% or more within the chart range (if possible).

2) There are minimal equity and royalty concerns.

3) Reservoir engineering concerns: The concern for well measurement accuracy declines, from a reservoir perspective, as the pool depletes. The applicant should provide its assessment/opinion, but the ERCB has to decide on a case-by-case basis if the concerns are relevant.

4) All gas meters producing into the same group measurement point use the same chart cycle, so that they are subject to the same type of error.

5.4 Gas Proration Outside Southeastern Alberta Shallow Gas Zones/Area

For wells outside the boundary of and/or producing from zones other than those approved for the Southeastern Alberta Shallow Gas Zones/Area (see 7.2), it may be acceptable to use a proration system for gas well production instead of having measurement for every well. If a proration system is implemented, all wells in the battery must be subject to the proration system.

5.4.1 Exceptions

Gas wells may be produced without individual well measurement and be connected to a proration battery without ERCB site-specific approval if all the initial qualifying criteria below are met and no application is required.

Initial Qualifying Criteria

1) All wells are classified as gas wells.

2) All wells flowing to the battery have common ownership and either common Crown or Freehold royalty, or

- if there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received;
- if there are no common Crown or Freehold royalties and there are only Freehold royalties involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalties involved, the licensee must apply to the ERCB for approval.

3) The licensee has discussed and addressed reservoir engineering issues with its own reservoir engineering staff or external knowledgeable personnel to ensure minimal reservoir engineering concerns and has documented the results for audit.

4) Total liquid production at each well in the battery is ≤ 2 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.

5) The maximum average daily well gas flow rate of all wells in the battery is ≤ 10.0 10^3 m^3/d (including gas equivalent volume of condensate), with the highest daily well flow rate ≤ 16.9 10^3 m^3 (including gas equivalent volume of condensate and except as allowed below). If an existing battery with measured gas well production is being converted to a proration battery, qualifying flow rates must be based on the monthly average flow rates recorded during the six consecutive months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.

6) Periodic well tests are conducted under normal operating conditions to determine hourly flow rates that will be used to estimate monthly well production based on monthly well operating hours. The well tests are conducted for a minimum of 12 hours, and all gas, condensate, and water volumes are separated and measured during the test. For gas wells with minimal water production (≤ 0.01 m^3 water/10^3 m^3 gas) and no condensate or oil, the testing duration must be sufficient to clearly establish stabilized flow rates and single-phase testing is allowed.

7) Following the commencement of production at the proration battery, all wells are tested within the first month, then again within six months, and then annually after that. New wells added to the battery at some future date must be tested within the first month of production, then again within six months, and then annually after that.

8) For new wells tying into a gas proration battery and that will be producing more than 16.9 10^3 m^3/d but that are expected to drop below 16.9 10^3 m^3/d within six months, every well must be tested monthly for the first six months with a separator, or until the production rate has stabilized, and annually thereafter. If the gas production rate for any of the wells is more than 16.9 10^3 m^3/d after six months of production or the liquid production rate is higher than 2 m^3/d, a separator must be installed to continuously separate and measure the well production, and the measurement-by-difference rules in Section 5.5 apply in this case.

9) For coalbed methane (CBM) wells and wells producing from above the base of groundwater protection each with water production ≤ 0.01 m^3 water/10^3 m^3 gas and no

condensate, if at any time more than 30.0 m^3/month of net water production is realized at the group measurement point, the operator must investigate the source of the water production by retesting and using at least a two-phase separator at the suspected gas well(s) within 30 days and then prorate the water production accordingly.

10) The flow rates established from the well tests are used to determine estimated monthly well production from the date of the test until the date of the next test, with the exception that the test conducted during the first month of production is also used to estimate the wells' production for the producing days prior to the test. The total measured group gas and liquid production are prorated to the wells, based on each well's estimated production, to determine the actual well production.

Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) An oil well is added to the battery, or one or more of the existing gas wells has been reclassified as an oil well.

2) The maximum average daily flow rate of all wells in the battery for any month exceeded 10.0 10^3 m^3/d, or the highest single well flow rate exceeded 16.9 10^3 m^3/d except as allowed above.

3) Total liquid volume exceeded 2 m^3/d during a 24-hour test period or prorated to 24 hours if the test period is not 24 hours.

4) A new well has been added to the proration battery with a daily flow rate over 16.9 10^3 m^3 except as allowed above or whose additional volume will cause the average daily well gas flow rate of all wells in the battery to exceed 10.0 10^3 m^3/d.

5) Wells within the proration battery or new wells added to the battery were not tested as required.

6) The gas proration methodology in item 10 under Initial Qualifying Criteria above was not followed.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.4.2 Applications

The following information must be submitted with an application to use a proration system, instead of individual gas well measurement, to determine gas well production if the above criteria are not met:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) a discussion of the stage of depletion for pools involved and the impact of any reduction in well measurement accuracy that may result from gas proration as it relates to reservoir engineering data needs—discussion of this matter by the licensee with its own reservoir engineering staff or knowledgeable external personnel is required and must be addressed in the application;

3) a clear explanation and flow diagram of proposed well and group measurement devices and locations, the proposed accounting and reporting procedures, and the proposed method and frequency of testing;

4) if there is no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received.

5.4.3 Considerations for Site-specific Approval

1) All wells must be classified as gas wells.

2) There are minimal equity, royalty, and reservoir engineering concerns.

3) All wells should have similar flow rates.

4) Economic considerations: Would implementation of a proration system reduce costs enough to significantly extend operations? Have other options been considered?

5) Total liquid production at each well in the battery should be ≤ 2 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.

5.5 Measurement by Difference

Measurement by difference (MbD) is defined as any situation where an unmeasured volume is determined by taking the difference between two or more measured volumes. It results in the unmeasured volume absorbing all the measurement error associated with the measured volumes. In the case of a proration battery (effluent measurement, or periodic testing without continuous measurement), new gas or oil source errors may be difficult to detect because the proration testing errors in the original system can hide the new source errors. Despite these concerns, a properly designed and operated measurement system can minimize the risk and attain reasonable accuracy, provided that the measured source gas or oil rates are a small proportion of the total system delivery rates. MbD is not allowed for "multiwell group batteries," "single-well batteries," or "sales points" unless special approval is obtained from the ERCB.

5.5.1 Gas Measurement by Difference

For gas proration batteries, MbD can include but is not limited to the following situations. (Note that all schematics below are examples only; some systems may be configured differently.)

Measured gas source(s) (other than from the designated SE Alberta Shallow Gas Zones/Area) delivering into a SE Alberta Shallow Gas proration battery (Figure 5.1):

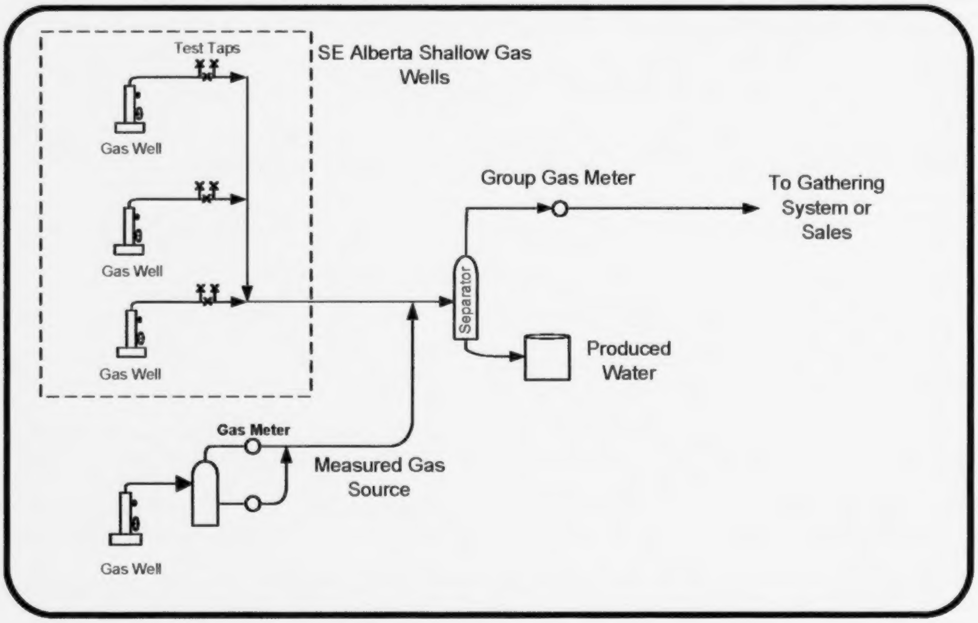

Test Taps
SE Alberta Shallow Gas Wells
Gas Well
Gas Well
Gas Well
Group Gas Meter
To Gathering System or Sales
Separator
Produced Water
Gas Meter
Measured Gas Source
Gas Well

Figure 5.1

- Measured gas source(s) delivering into a gas proration battery outside SE Alberta Shallow Gas Zones/Area (Figure 5.2):

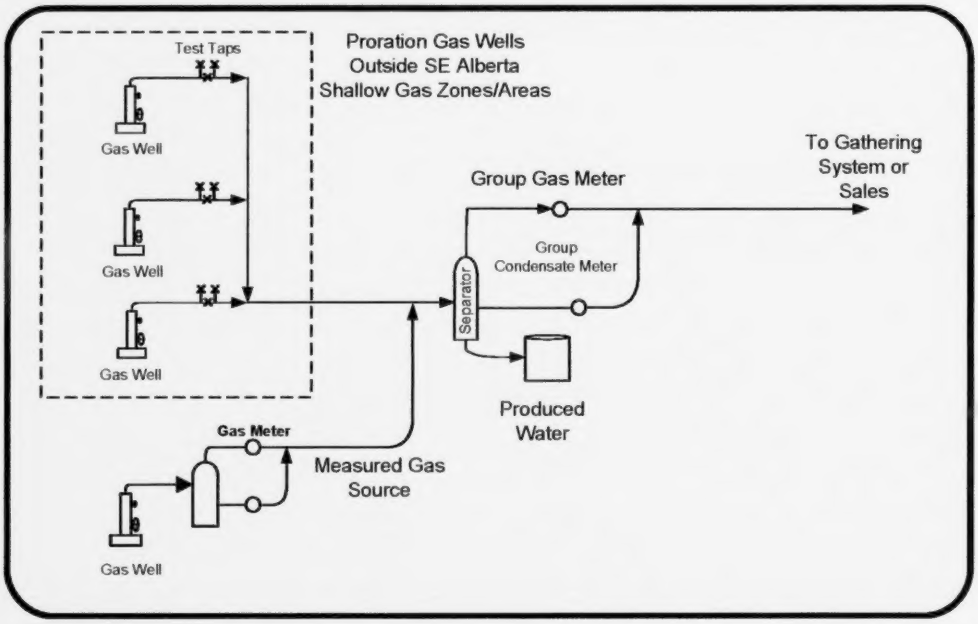

Test Taps
Proration Gas Wells Outside SE Alberta Shallow Gas Zones/Areas
Gas Well
Gas Well
Gas Well
To Gathering System or Sales
Group Gas Meter
Group Condensate Meter
Separator
Produced Water
Gas Meter
Measured Gas Source
Gas Well

Figure 5.2

- Measured gas source(s) delivering into an effluent (wet) measurement gas proration battery (Figure 5.3):

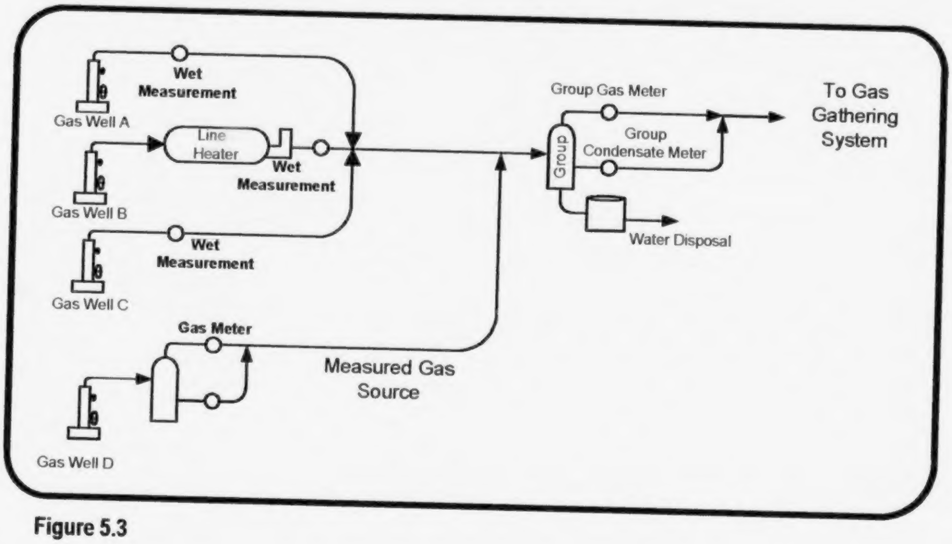

Wet Measurement
Gas Well A
Line Heater
Wet Measurement
Gas Well B
Wet Measurement
Gas Well C
Gas Meter
Measured Gas Source
Gas Well D
Group Gas Meter
Group
Group Condensate Meter
Water Disposal
To Gas Gathering System

Figure 5.3

- Measured gas source(s) delivering into an oil proration battery (Figure 5.4):

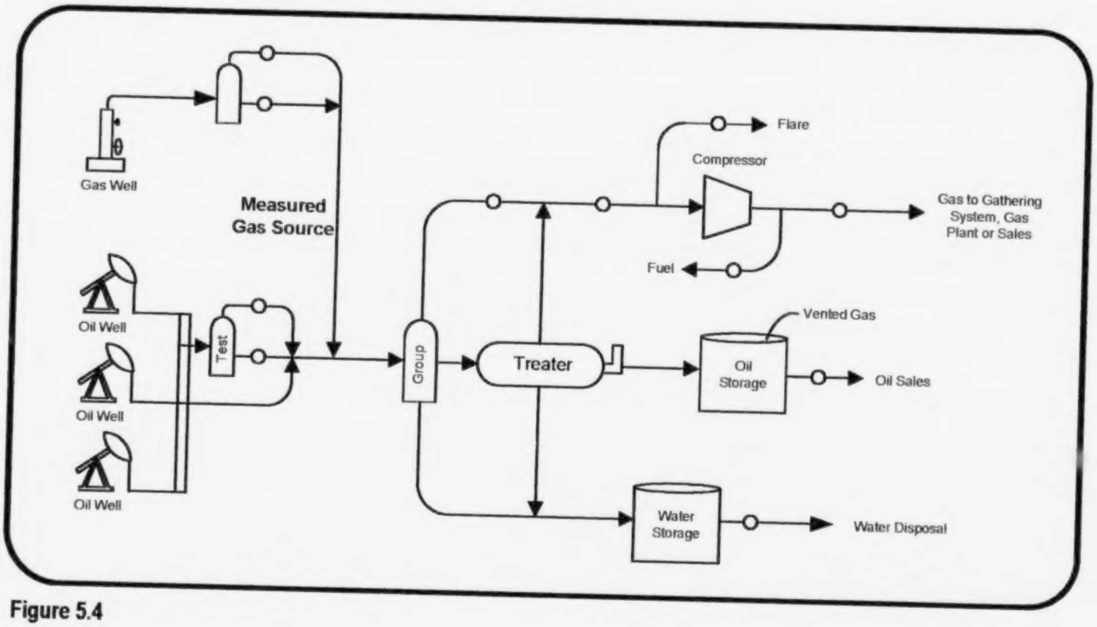

Gas Well
Measured Gas Source
Oil Well
Oil Well
Oil Well
Test
Group
Treater
Flare
Compressor
Gas to Gathering System, Gas Plant or Sales
Fuel
Vented Gas
Oil Storage
Oil Sales
Water Storage
Water Disposal

Figure 5.4

- Measured oil facility gas delivering into a gas proration battery (Figure 5.5):

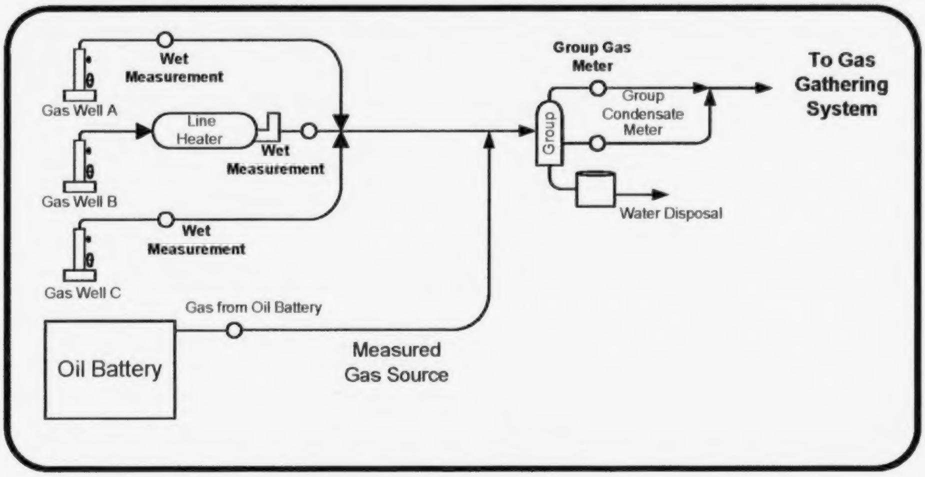

Wet Measurement
Gas Well A
Line Heater
Wet Measurement
Gas Well B
Wet Measurement
Gas Well C
Gas from Oil Battery
Oil Battery
Measured Gas Source
Group Gas Meter
Group
Group Condensate Meter
Water Disposal
To Gas Gathering System

Figure 5.5

If any measured gas source will be tied in to a gas proration battery:

1) The gas and liquids from all tied-in gas sources must be separately and continuously measured. If the R ratio below cannot be met, the operator may consider some of the tied-in measured gas wells as continuous or 31-day test and include them as part of the gas proration battery. These wells, however, must be tagged as "continuous test."

2) The monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly disposition gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

3) The table below indicates when measurement by difference may be acceptable by exception and when submission of an application may be required.

Prorated gas flow rate (excluding all measured gas source)		**R* ratios**	
≤0.5 10^3 m^3/d	< 1.00		
>0.5 10^3 m^3/d	≤ 0.35	> 0.35	> 0.75
Application required	**No**	**Yes**	**Yes** **(Approval granted only in exceptional circumstances)**

*R = Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to the total battery gas disposition volume (including fuel, flare, and vent volumes).

If any measured gas source will be tied in to an oil battery:

1) The gas and liquids from the tied-in gas source(s) must be separately and continuously measured.

2) The monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the

total monthly battery gas volume to determine the monthly battery gas production volume. (See Table 5.1 for options.)

3) **If liquid condensate is received from a tied-in measured gas source, the monthly liquid condensate volume** where appropriate **must be subtracted from the total monthly oil disposition (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil production volume.** (See Table 5.1 for options.)

Scenario 1

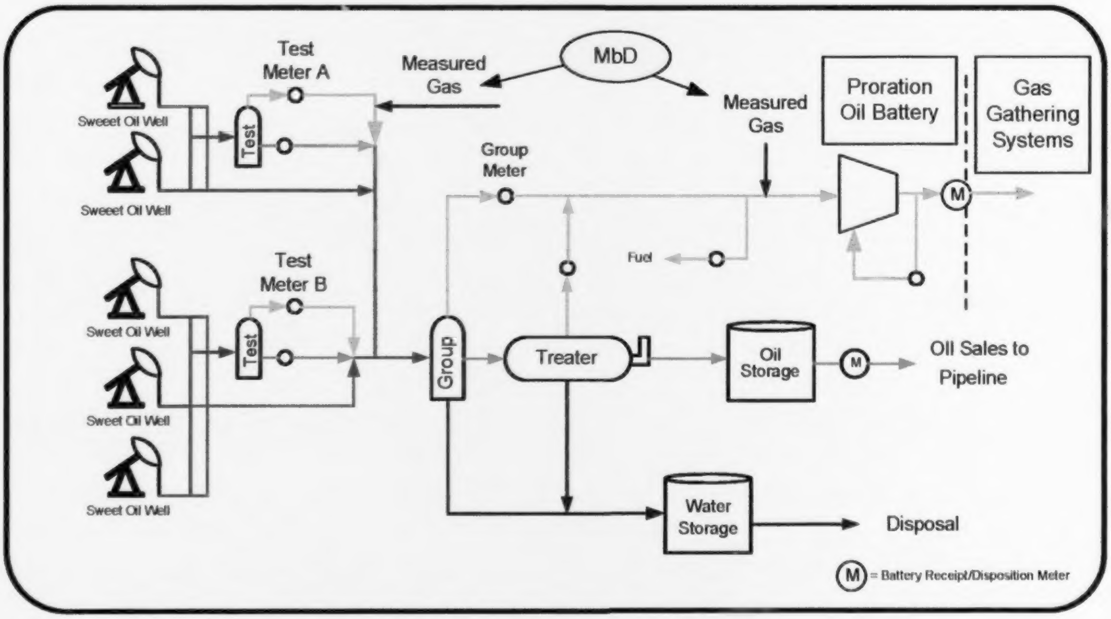

Sweeet Oil Well
Sweeet Oil Well
Test Meter A
Test
Measured Gas
MbD
Measured Gas
Proration Oil Battery
Gas Gathering Systems
Group Meter
Fuel
M
Sweet Oil Well
Sweet Oil Well
Sweet Oil Well
Test Meter B
Test
Group
Treater
Oil Storage
M
Oil Sales to Pipeline
Water Storage
Disposal
M = Battery Receipt/Disposition Meter

Figure 5.6. Measured gas coming into oil battery with measurement by difference

Facility delineation in Figure 5.6 is determined by where the measured gas enters the oil battery relative to where the oil battery gas is measured.

Calculate Actual Battery Gas Production

Total battery gas disposition is equal to the metered volume after compression. The actual battery gas production is calculated by subtracting the measured gas receipt volumes from the total battery disposition plus fuel, flare, and vent and then prorated to the flow-lined oil wells. The amount of measured gas that can be delivered into the oil battery is limited by the measurement by difference (MbD) percentage in Section 5.5.

Calculate Battery Oil Production

If the measured gas streams have condensate, see Section 5.5.1, Table 5.1 and Table 5.2, and Section 14.3 on how to calculate and report condensate shrinkage, flashing, disposition, and receipt.

Scenario 2

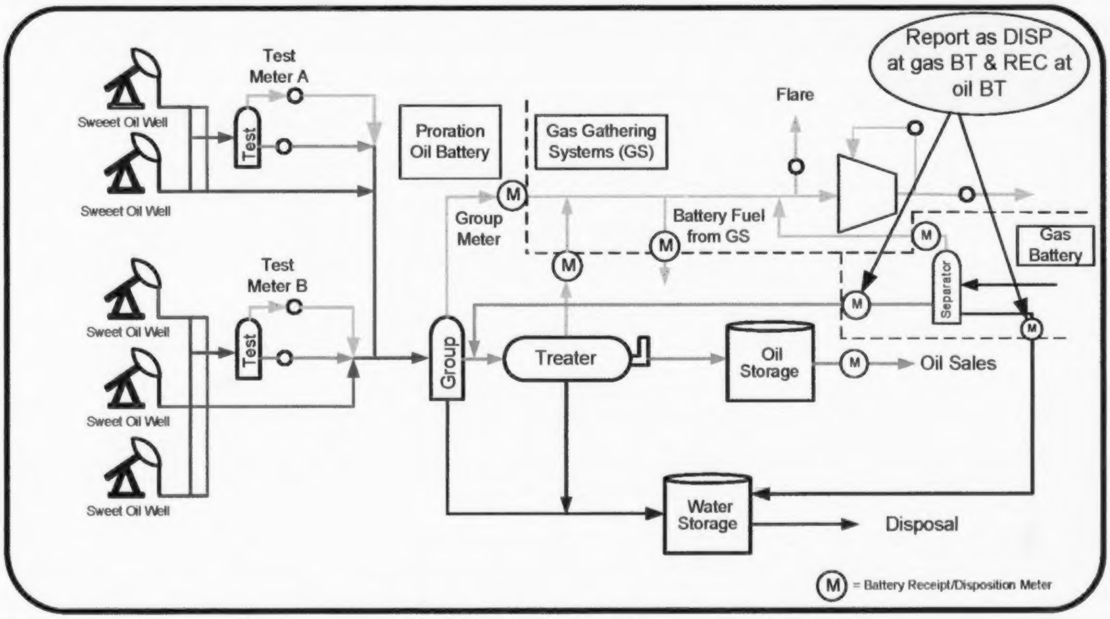

Sweeet Oil Well
Sweeet Oil Well
Sweet Oil Well
Sweet Oil Well
Sweet Oil Well
Test Meter A
Test
Test Meter B
Test
Proration Oil Battery
Gas Gathering Systems (GS)
M
Group Meter
Battery Fuel from GS
Flare
Report as DISP at gas BT & REC at oil BT
Gas Battery
Separator
Group
Treater
Oil Storage
Oil Sales
Water Storage
Disposal
M = Battery Receipt/Disposition Meter

Figure 5.7. Measured gas battery delivering hydrocarbon liquids and water to an oil battery

Calculate Actual Oil Battery Gas Production

Total of group and treater gas is prorated back to flow-lined oil wells. Gas meter off separator coming from the measured gas battery is reported as a delivery to the GS. This is a preferred scenario as you are not restricted by gas measurement by difference, but oil measurement by difference still applies.

Condensate Receipt into Oil Battery

Condensate measured at the gas battery separator is generally reported as a liquid disposition from the gas facility into the oil battery. See Section 5.5.1, Table 5.1 and Table 5.2, and Section 14.3 on exceptions and how to calculate and report condensate shrinkage, flashing, disposition, and receipt.

4) **The table below indicates when measurement by difference may be acceptable by exception and when submission of an application may be required.**

Prorated gas flow rate (excluding all measured gas source)	**R* ratios**		
≤0.5 10^3 m^3/d	< 1.00		
>0.5 10^3 m^3/d	≤ 0.35	> 0.35	> 0.80
Application required	**No**	**Yes**	**Yes (Approval granted only in exceptional circumstances)**

*R = Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to the total battery gas disposition volume (including fuel, flare, and vent volumes).

Where a measured gas source will be tied into a single well battery, as shown in Figure 5.8, this situation does not qualify for an exception, and an application must be submitted to and approved by the ERCB prior to implementation.

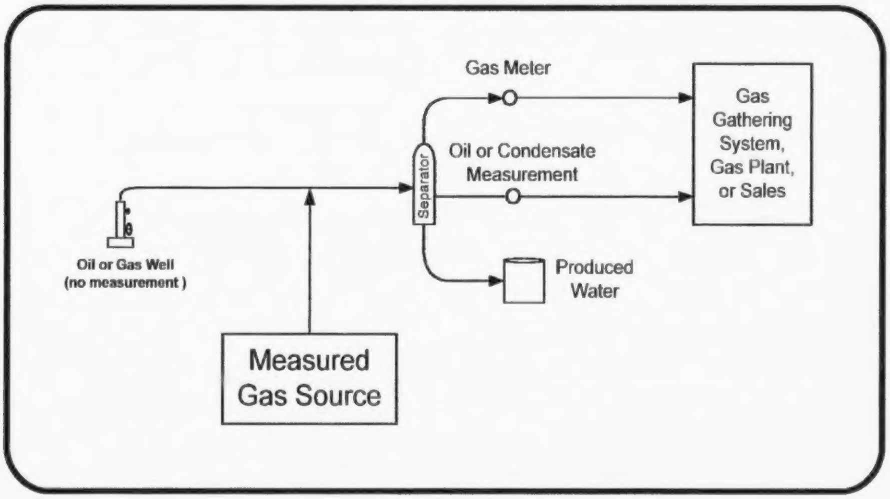

Gas Meter
Gas Gathering System, Gas Plant, or Sales
Oil or Condensate Measurement
Separator
Oil or Gas Well (no measurement)
Produced Water
Measured Gas Source

Figure 5.8

5.5.2 Oil Measurement by Difference

For oil streams, measurement by difference can include but is not limited to the following situations.

- Measured oil and/or oil-water emulsion from a battery delivering into an oil proration battery by truck (Figure 5.9):

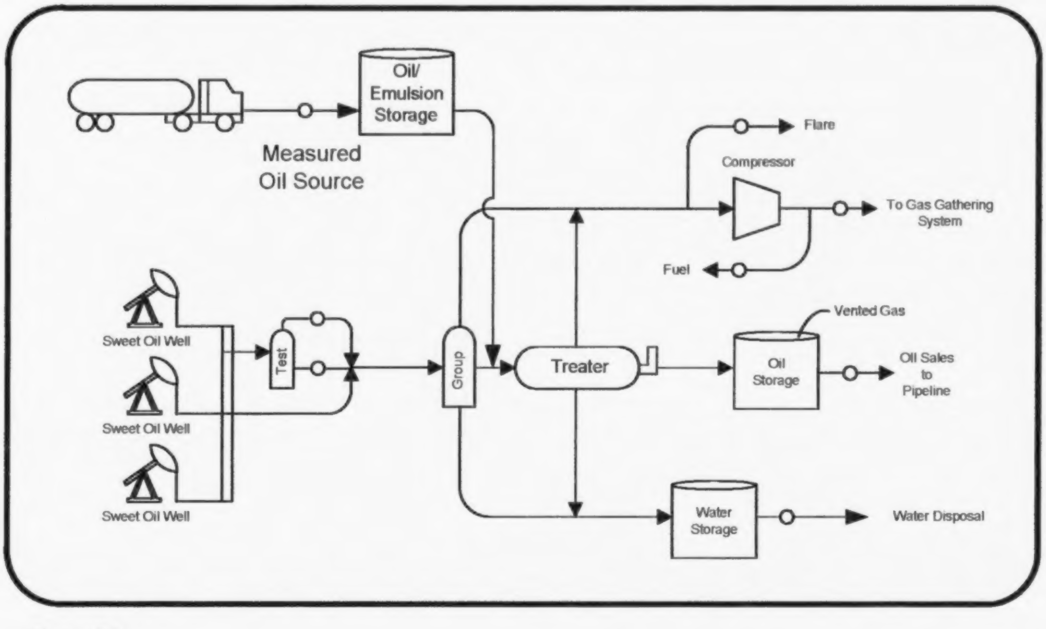

Oil/ Emulsion Storage
Measured Oil Source
Flare
Compressor
To Gas Gathering System
Fuel
Vented Gas
Sweet Oil Well
Test
Group
Treater
Oil Storage
Oil Sales to Pipeline
Sweet Oil Well
Sweet Oil Well
Water Storage
Water Disposal

Figure 5.9

- Measured oil and/or oil-water emulsion (and gas if applicable) under pressure from a battery delivering into an oil proration battery by pipeline (Figure 5.10):

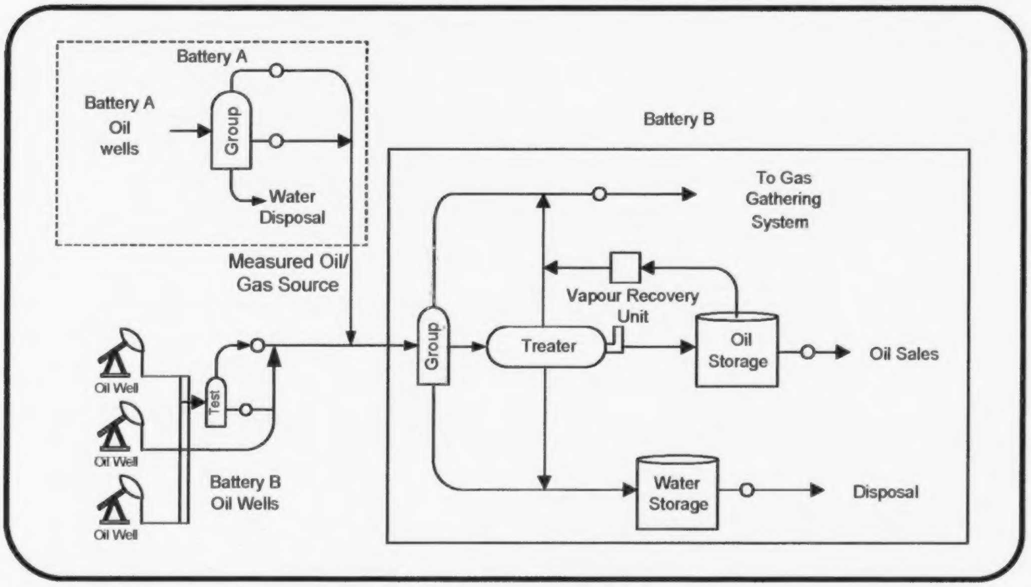

Battery A
Battery A Oil wells
Group
Water Disposal
Measured Oil/ Gas Source
Battery B
To Gas Gathering System
Vapour Recovery Unit
Group
Treater
Oil Storage
Oil Sales
Test
Oil Well
Oil Well
Oil Well
Battery B Oil Wells
Water Storage
Disposal

Figure 5.10

If any measured oil and/or oil-water emulsion source will be delivered to a battery including trucked-in volumes:

1) Measured oil and/or oil-water emulsion delivery/receipt volumes must be determined using equipment and/or procedures that meet delivery point measurement uncertainty requirements. In the case of oil-water emulsions, the measurement uncertainty requirements apply to total volume determination only.

2) Measured oil volumes must be determined and reported at stock tank conditions.

3) The liquids received from the delivered measured oil and/or oil-water emulsion source(s) must be subtracted from the total monthly oil and water disposition volumes (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil production volume.

4) The table below indicates when measurement by difference may be acceptable by exception and when submission of an application may be required.

Measured oil delivery/receipt volume	Application required
≤ 1000 m^3/month or if > 1000 m^3/month and ≤ 25% of monthly prorated battery oil production volume	No
> 1000 m^3/month and > 25% of monthly prorated battery oil production volume	Yes

5) Consideration should be given to incorporating the piped-in measured oil and/or oil-water emulsion source(s) as a satellite of the battery (if the battery is an oil proration battery) and including it in the battery's proration system. In that case, measurement by difference could be avoided. A pipelined single oil well or oil wells in a multiwell group may also

be considered as continuous or 31-day test and included as part of the oil proration battery. These wells, however, must be tagged as "continuous test."

5.5.3 Exceptions

Measurement by difference is allowed without ERCB site-specific approval if all of the applicable criteria below are met and no application is required.

If the measurement by difference will involve existing production, initial qualifying flow rates must be based on average daily flow rates (monthly flow rate divided by number of production days in the month) recorded during the six months prior to implementation of the measurement by difference. If new measured production is to be connected to a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions.

5.5.3.1 Exceptions for All Measured Gas Streams

For measured gas source(s) from either gas or oil batteries tied into a gas proration battery or an oil battery:

5.5.3.1(a) Initial Qualifying Criteria

1) Volumetric criteria for measured gas tying into a proration battery

Prorated gas flow rate (excluding all measured gas source)	R*
$\leq 0.5\ 10^3\ m^3/d$	< 1.00
$> 0.5\ 10^3\ m^3/d$	≤ 0.35

*R = Ratio of volume of all tied-in measured gas (including GEV of condensate where applicable) to the total gas disposition volume from the receiving battery (including fuel, flare and vent volumes).

Example:

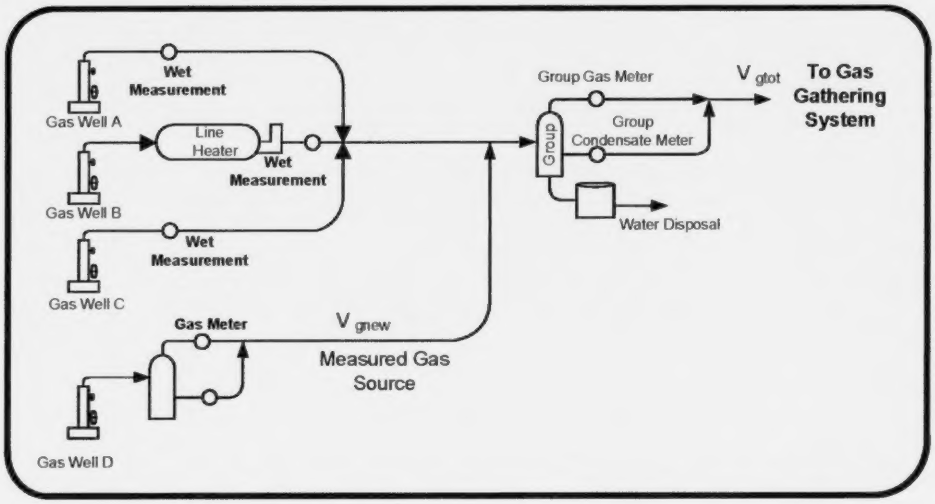

Wet Measurement
Gas Well A
Line Heater
Wet Measurement
Gas Well B
Wet Measurement
Gas Well C
Gas Meter
V_{gnew}
Measured Gas Source
Gas Well D
Group Gas Meter
V_{gtot}
To Gas Gathering System
Group
Group Condensate Meter
Water Disposal

Figure 5.11

For the gas battery example in Figure 5.11,

$V_{gtot} = 100\ 10^3\ m^3/d$ (total of measured gas and GEV of condensate delivered out of the battery, including volumes received from Gas Well D)

$V_{gnew} = 30\ 10^3\ m^3/d$ (total of measured gas and GEV of condensate delivered to the battery from Gas Well D)

Prorated gas flow rate = $V_{gtot} - V_{gnew} = 100 - 30 = 70\ 10^3\ m^3/d$

$R = 30/100 = 0.3$

Since the prorated flow rate is above $0.5\ 10^3\ m^3/d$ and R is below 0.35 for the Well D tie-in, it is within the acceptable exception range.

2) All proration wells flowing to the battery have common ownership and either common Crown or Freehold royalty.
   - If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.
   - If there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the licensee must apply to the ERCB for approval if there is any Freehold objection.

3) The gas and liquid phases from the tied-in measured gas source(s) are separately and continuously measured.

4) Gas volumes received at a gas battery from the tied-in measured gas source(s) include the GEV of the measured condensate volumes if the condensate is recombined with the measured gas volumes from the new tied-in gas source.

5) If the tied-in measured gas source(s) produces condensate and it is to be connected to an oil battery, the licensee must choose from the applicable condensate delivery/reporting options in Table 5.1 below.

Table 5.1. Criteria for condensate (diluent) delivery to an oil battery

Condensate rate (from measured gas sources)	≤ 2.0 m^3/day and/or ≤ 5.0% of total prorated oil production	> 2.0 m^3/day and/or > 5.0% of total prorated oil production
Option 1	Deliver condensate to the oil battery and report it all as liquid condensate if most of the condensate will not be flashed during the oil treatment process (minimal pressure drop and/or temperature increase).	Deliver condensate elsewhere; do not recombine it with the gas volumes delivered to the oil battery.
Option 2	Deliver condensate to the oil battery and report it all as a GEV if most of the condensate will be flashed during the oil treatment process (large pressure drop and/or temperature increase).	Tie in the gas well gas and condensate stream downstream of oil battery gas disposition measurement.
Option 3	Deliver condensate elsewhere; do not recombine it with the gas volumes delivered to the oil battery.	

6) If condensate from a tied-in measured gas source will be delivered to an oil battery and reported as a liquid volume, it is measured with a meter proved to stock tank conditions.

7) If condensate from a tied-in measured gas source will be delivered to an oil battery and reported as a GEV, it is measured with a meter proved to flow line conditions.

8) In the case of an oil battery or a gas proration battery, the monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) is subtracted from the total monthly battery gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

9) In the case of an oil battery, the monthly liquid condensate volume (where appropriate) received from a tied-in measured gas source is subtracted from the total monthly oil disposition (plus inventory changes, shrinkage, if applicable, and minus any other receipts) to determine the monthly battery oil production volume.

10) If oil and/or oil-water emulsion from a tied-in measured gas source will be delivered to a gas proration battery, the total volume does not exceed 2 m^3/day, it is measured with a meter proved to stock tank conditions, and it is reported as a liquid.

5.5.3.1(b) Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) The gas and liquid phases from the tied-in measured gas source(s) were not separately and continuously measured.

2) Measurement, accounting, and reporting of condensate in items 4 to 9 under Initial Qualifying Criteria above were not followed.

3) Measurement, accounting, and reporting of oil and/or oil-water emulsion in item 10 under Initial Qualifying Criteria above were not followed.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.5.3.2 Exception for Measured Oil Streams Received by Truck

5.5.3.2(a) Initial Qualifying Criteria

1) Oil and/or oil-water emulsions may be trucked into an oil battery provided the total measured oil receipt volume is ≤ 1000 m^3/month, or if > 1000 m^3/month, the total measured oil receipt volume is ≤ 25% of the monthly battery oil production volume unless option (2) under Section 5.5.3.2(b) has been implemented.

2) The monthly battery oil and water production volumes are determined by subtracting the monthly measured oil and water receipt volumes from the total monthly battery oil and water disposition volumes (plus inventory change and minus any other receipts).

5.5.3.2(b) Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) Trucked-in oil receipt was > 1000 m^3/month and the total measured oil receipt volume was > 25% of the monthly battery oil production volume.

2) The accounting methodology in item 2 under Initial Qualifying Criteria above was not followed.

There are three options to follow after revocation:

1) truck all oil receipts over 1000 m^3/month elsewhere, or

2) set up another treater train with separate inlet measurement, tankage, and outlet measurement to process the truck-in receipts prior to commingling with the battery production, or

3) obtain ERCB special approvals to continue.

5.5.3.3 Exception for Measured Oil Streams Received by Pipeline

5.5.3.3(a) Initial Qualifying Criteria

1) Oil and/or oil-water emulsions may be pipelined into an oil battery provided that the total measured oil receipt volume is < 1000 m^3/month or if > 1000 m^3/month, the total measured oil receipt volume is ≤ 25% of the monthly battery oil production volume.

2) All wells that belong to the oil battery and the tied-in oil source(s) have common ownership and either common Crown or Freehold royalty:

   - If there is no common ownership, written notification has been given to all working interest participants, with no resulting objections.

   - If there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalties involved, the licensee must apply to the ERCB for approval.

3) The monthly battery oil and water production volumes are determined by subtracting the monthly measured oil and water receipt volumes from the total monthly battery oil and water disposition volumes (plus inventory change and minus any other receipts).

4) If the measured gas from a measured live oil/emulsion production source is also commingled with the production at an oil battery, the exception criteria for gas measurement by difference are also met.

5.5.3.3(b) Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) Piped in oil receipt was > 1000 m^3 and the total measured oil receipt volume was > 25% of the monthly battery oil production volume.

2) The accounting methodology in item 3 under Initial Qualifying Criteria above was not followed.

3) Gas measurement by difference exception criteria in item 4 under Initial Qualifying Criteria above was not met.

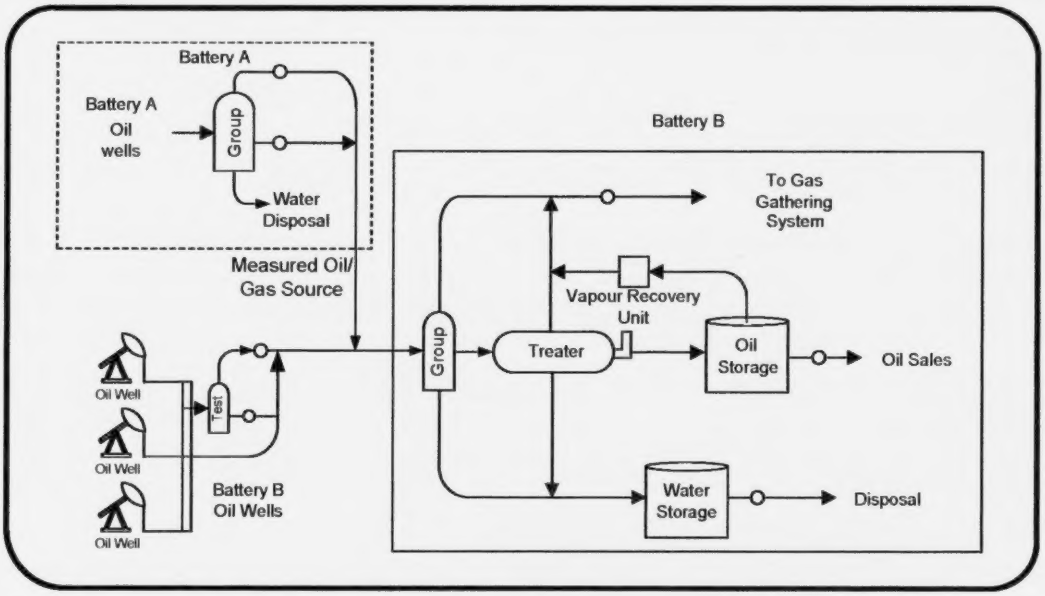
There are three options to follow after revocation:

1) pipe all oil receipts over 1000 m^3/month elsewhere, or

2) set up another treater train with separate inlet measurement, tankage, and outlet measurement to process the pipeline receipts prior to commingling with the battery production, or

3) obtain ERCB special approvals to continue.

Oil System Example:



Battery A
Battery A
Oil
wells
Group
Water
Disposal
Measured Oil/
Gas Source
Battery B
To Gas
Gathering
System
Vapour Recovery
Unit
Group
Treater
Oil
Storage
Oil Sales
Oil Well
Oil Well
Oil Well
Test
Battery B
Oil Wells
Water
Storage
Disposal

Figure 5.12

Note that with the addition of Battery A production, if the measurement by difference meets all the initial qualifying criteria and the total oil delivery volume at Battery B is over 100 m^3/d, the delivery volume must be determined by a measurement device(s) and/or procedures having ± 0.5% uncertainty, which might require changes in measurement equipment and/or procedures at Battery B.

For this example (Figure 5.12), given the following data,

Battery A oil production volume = 20.0 m^3/d

Battery B oil production volume = 90.0 m^3/d before tying in Battery A

Battery A gas production volume = 15.0 10^3 m^3/d

Battery B gas production volume = 20.0 10^3 m^3/d before tying in Battery A

Step 1: Calculate the monthly measured oil volume from Battery A delivered to the proration battery (Battery B) and the percentage of the prorated oil production:

Monthly measured oil production volume from Battery A = 20.0 m^3/d x 30 days = 600 m^3

Battery A oil volume as a percentage of Battery B oil production volume =
20 m^3/d / 90.0 m^3/d = 22.2%

Step 2: Calculate the R ratio for the commingled gas:

R = 15.0/(15.0 + 20.0) = 0.43

Since the Battery A monthly measured oil volume is below 1000 m^3/month, the oil volumetric criteria are met. However, the gas R ratio is over the 0.35 limit, so an application would be required.

5.5.4 Applications

The following information must be submitted with an application to add measured gas or oil/emulsion sources to a proration battery if the above criteria are not met:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) a discussion of the stage of depletion for pools involved, and the impact of any reduction in well measurement accuracy that may result from measurement by difference as it relates to reservoir engineering data needs; discussion of this matter by the proponent with its own reservoir engineering staff or knowledgeable external personnel is required and must be addressed in the application;

3) if there are no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received.

5.5.5 Considerations for Site-specific Approval

1) There are minimal equity, royalty, and reservoir engineering concerns.

2) Economic considerations: Would implementation of a proration system reduce costs enough to significantly extend operations? Have other options been considered?

3) The gas and liquids from the tied-in measured source(s) must be separately and continuously measured.

4) If the tied-in measured gas source(s) produces condensate and it is to be connected to an oil battery, the licensee must choose from the following applicable condensate delivery/reporting options:

Table 5.2. Options for condensate (diluent) delivery to an oil battery

Condensate rate (from measured gas sources)	≤ 2.0 m^3/day and/or ≤ 5.0% of total prorated oil production	> 2.0 m^3/day and/or > 5.0% of total prorated oil production
Option 1	Deliver condensate to the oil battery and report it all as liquid condensate if most of the condensate will not be flashed during the oil treatment process (minimal pressure drop or temperature increase).	A laboratory analysis, or a computer software simulation based on the condensate composition must be performed to determine the amount of the condensate that will be flashed during the oil treatment process. **Flashed condensate:** report it as a GEV of condensate and include it with the gas delivery/receipt volume. **Unflashed condensate:** report it as a liquid condensate delivery/receipt volume.
Option 2	Deliver condensate to the oil battery and report it all as a GEV if most of the condensate will be flashed during oil treatment process.	Deliver condensate elsewhere and do not deliver it to the oil battery.
Option 3	Deliver the condensate elsewhere and do not deliver it to the oil battery.	

5) In the case of an oil battery or a gas proration battery, the monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly battery gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

6) In the case of an oil battery, the monthly liquid condensate, or oil, and/or oil-water emulsion volume (where appropriate) received from a tied-in measured source must be subtracted from the total monthly oil and/or water disposition (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil and/or water production volume.

5.6 Surface Commingling of Multiple Gas Zones/Wells

If gas wells have been completed in multiple zones and those zones are segregated in the wellbore and produced separately to surface or if there are multiple individual gas wells on the same surface location, production from each zone or each well usually has to be measured separately prior to commingling. Where applicable, such zones or wells may be commingled at surface prior to the combined production being measured, if the conditions in the "Exceptions" section below are met or upon approval of an application. Proportionate monthly production volumes must still be determined and reported for each zone/well, in accordance with the applicable procedures described below.

The following requirements do not apply to zones that qualify for the SE Alberta Shallow Gas Proration Battery procedures if specific zones are approved (without application) for commingling in the wellbore.

Commingling of zones in the wellbore require approval from the ERCB Resources Applications Group.

5.6.1 Exceptions

Surface commingling of two gas zones in a gas well or separate gas wells on the same surface location prior to measurement is allowed without ERCB site-specific approval if all the initial qualifying criteria below are met and no application is required.

Initial Qualifying Criteria

1) Both zones/wells have common ownership and common Crown or Freehold royalty:

    - If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.
    - If there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalties involved, the licensee must apply to the ERCB for approval.

2) Monthly average of total liquid production from both zones is ≤ 2 m^3/d.

3) The combined daily flow rate of both zones/wells is ≤ 16.9 10^3 m^3, including GEV of condensate (if recombined). If the zones/wells to be commingled will involve existing production, initial qualifying flow rates are based on monthly average flow rates recorded during the six months prior to implementation of the commingling. If new zones/wells are to be commingled, the initial qualifying flow rates are based on production tests conducted under the anticipated operating conditions.

4) Shut-in wellhead pressure of the lower pressure zone/well is $\geq 75\%$ of the shut-in wellhead pressure of the higher-pressure zone.

5) The combined production from both zones/wells is measured continuously. Separation before measurement is required for both phases.

6) Check valves are installed on each flow line upstream of the commingling point.

7) Testing requirements:

    - Each zone/well must be tested once per month for the first six months after commingling, then annually thereafter, and/or immediately following any significant change to the producing conditions of either zone/well.
    - The tests must be conducted for at least 24 hours and must involve the separation and measurement of all gas and liquid production.
    - If condensate is recombined with the gas production of the commingled zones/wells, a sample of the condensate must be taken annually and analyzed and used to determine the factor to be used to determine the GEV.
    - The tests for both zones/wells must be done consecutively with stabilization periods.
    - Any of the three test methods described below may be used. However, methods (i) and (ii) below are preferred, because the testing is conducted under normal flowing conditions without shutting in zones/wells, so that minimal stabilization time is required.

i) Test taps must be installed upstream of the commingling point but downstream of the check valve so that a test separator unit can be hooked up to test each zone/well individually (Figure 5.13).

Test Method (i)

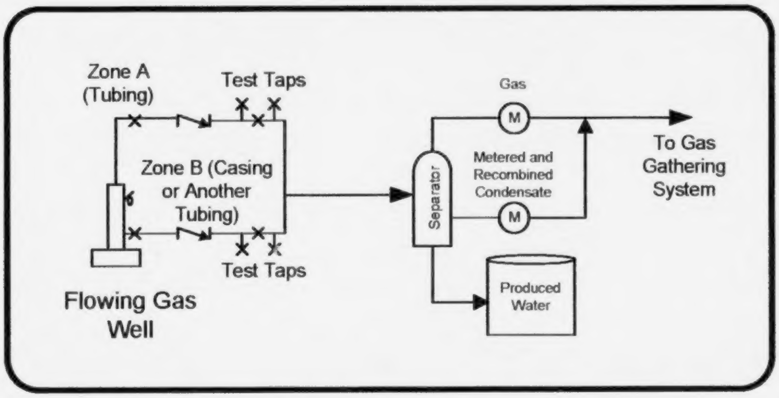

Zone A
(Tubing)
Test Taps
Zone B (Casing
or Another
Tubing)
Test Taps
Flowing Gas
Well
Separator
Gas
M
Metered and
Recombined
Condensate
M
Produced
Water
To Gas
Gathering
System

Figure 5.13

ii) Install permanent bypasses or taps to hook up temporary bypasses downstream of the check valve so that one zone/well will be bypassing the existing separation and metering equipment while the other zone/well is tested using the existing equipment. Note that the production from the bypassed zone/well must be estimated based on the production test rates (Figure 5.14).

Test Method (ii)

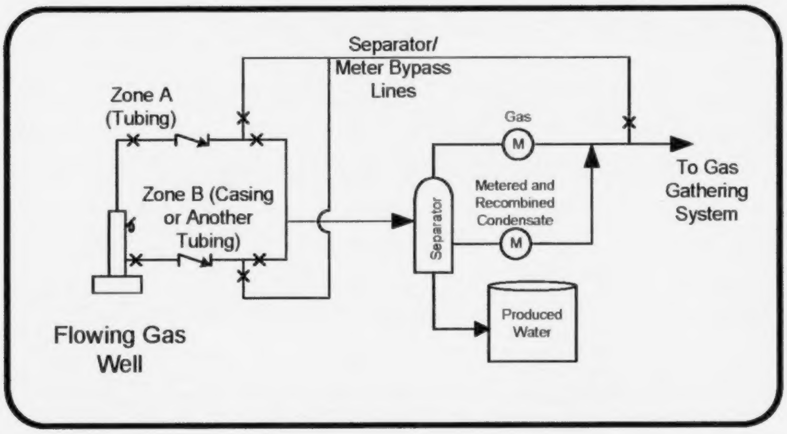

Separator/
Meter Bypass
Lines
Zone A
(Tubing)
Zone B (Casing
or Another
Tubing)
Flowing Gas
Well
Separator
Gas
M
Metered and
Recombined
Condensate
M
Produced
Water
To Gas
Gathering
System

Figure 5.14

iii) Shut in one producing zone at a time and use the existing separation and measurement equipment to test each zone/well individually after stabilization.

8) The production rates determined for each zone/well by the periodic tests must be used to estimate the monthly production for each zone/well from the date they are conducted until the next test is conducted. The monthly measured combined production must be

prorated to each zone/well based on the estimates, and those prorated volumes must be reported as the monthly production for each zone/well.

Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) The combined production from both zones/wells was not measured continuously or there was no separation before measurement.

2) Check valves were not installed on each flow line upstream of the commingling point.

3) Testing requirements in item 7 under Initial Qualifying Criteria above were not followed.

4) The gas proration methodology in item 8 under Initial Qualifying Criteria above was not followed.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.6.2 Applications

The following information must be submitted with an application to commingle production at surface prior to measurement from multiple zones in a gas well or multiple wells on the same surface location if the above criteria are not met:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) shut-in and proposed operating pressures at the wellhead for all zones/wells;

3) operating pressure for the gathering system at the well site measurement point;

4) proposed testing procedures to determine the individual zone/well production rates;

5) proposed accounting procedures for prorating total volumes to the individual zones/wells; and

6) if there are no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received.

5.6.3 Considerations for Site-specific Approval

1) Generally, there is ≤ 2 m^3/day of total liquid production from all zones/wells.

2) All zones/wells must be classified as gas zones/wells.

3) There are minimal equity, royalty, and reservoir engineering concerns.

4) The combined production of all zones/wells must be continuously measured. If there are gas and liquid components, they must be separately measured.

5) Check valves must be in place on the flow line upstream of the commingling point.

6) Testing requirements:

- Each zone/well must be tested once per month for the first six months after commingling, then annually after that, and/or immediately following any significant change to the producing conditions of either zone/well.

- The tests must be conducted for at least 24 hours in duration and must involve the separation and measurement of all gas and liquid production.

- If condensate is recombined with the gas production of the commingled zones/wells, a sample of the condensate must be taken annually and analyzed and used to determine the factor that will be used to determine the GEV.

- The tests for all zones/wells must be done consecutively, with stabilization periods.

- Any of the three test methods described in the exceptions section above may be used, with the consideration that more than two zones/wells may be involved. However, methods (i) and (ii) are preferred, because the testing is conducted under normal flowing conditions without shutting in zones/wells, so that minimal stabilization time is required. The ERCB may specify test procedures if specific circumstances warrant them.

7) The production rates determined for each zone/well by the periodic tests must be used to estimate the monthly production for each zone/well from the date they are conducted until the next test is conducted. The monthly measured combined production must be prorated to each zone/well based on the estimates, and those prorated volumes must be reported as the monthly production for each zone/well.

5.7 Gas Effluent Wells Exemption and Reduction for Testing Frequency

See Section 7.4 for the latest exemption and exceptions.

6 Conventional Oil Measurement

This section presents the base requirements and exceptions for conventional crude oil and emulsion measurements from wells and batteries in the upstream oil and gas industry that are used in determining volumes for reporting to the PRA. The requirements for crude oil/emulsion volumes transported by truck are detailed in Section 10.

Conventional crude oil has the following characteristics:

- it is a mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds,
- it is recovered or is recoverable at a well from an underground reservoir,
- it is liquid at the conditions under which its volume is measured or estimated, and
- it must have a density of less than 920 kg/m^3 at standard conditions.

6.1 General Requirements

Crude oil may be found in association with water in an emulsion. In such cases, the total liquid volume must be measured, and the relative volumes of oil and water in the emulsion must be determined by obtaining and analyzing a representative sample of the emulsion, by using a product analyzer, or by other means if applicable. Applications for which estimation of water content is appropriate (e.g., inventory) are covered in more detail later in this section.

A licensee must measure produced crude oil/emulsion volumes by tank gauging, weigh scale, or meter unless otherwise stated in this directive. The ERCB will consider an oil measurement system to be in compliance if the base requirements detailed below are met. The ERCB may stipulate additional or alternative requirements for any specific situation based on a site-specific assessment and will inform licensees in writing of any additional or alternative requirements respecting their facilities.

6.2 General Measurement, Accounting, and Reporting Requirements for Various Battery Types

6.2.1 General Accounting Formula

Production = Total disposition + Closing inventory – Opening inventory – Total receipts

6.2.2 Oil Batteries

6.2.2.1 General

All wells in the battery must be classified as oil wells.

Liquid production from an oil battery must be measured as an oil, water, or oil/water emulsion volume. This measurement may be performed at the battery site, a truck delivery/receipt point, or a pipeline delivery point. The meter factor obtained from meter proving must be applied to the meter volumes until another prove is conducted.

All wells in a multiwell oil battery must be subject to the same type of measurement (measured or prorated). If there is a mixture of measured and prorated wells within the same battery, the exception criteria in Section 5.5 must be met or an ERCB site-specific approval must be obtained.

Production from gas batteries or other oil/bitumen batteries may not be connected to an oil proration battery upstream of the oil proration battery group measurement point(s) unless specific criteria are met or an ERCB approval is obtained (see Section 5.5). For oil delivered to a gas system, see Section 6.2.3.1.

Any oil well that produces fluids from any formation is considered on production and a battery code is required to report the production on the PRA even for a "test." See *On-line Supplement to Directive 007: Volumetric and Infrastructure Requirements*, Appendix 8, for load fluid reporting.

6.2.2.2 Single-well Battery

Oil/emulsion must be separated from gas and measured.

6.2.2.3 Multiwell Group Battery

Each well must have its own separation and measurement equipment, similar to a single-well battery.

All equipment for the wells in the battery must share a common surface location.

6.2.2.4 Proration Battery

All well production is commingled prior to the total battery oil/emulsion being separated from the gas and measured. Individual monthly well oil production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor.

Double proration, whereby the proration oil battery disposition volume(s) is prorated to group/receipt measurement points and then further prorated to the wells, is allowed subject to the following conditions:

- All prorated oil/emulsion must be measured using measurement systems that meet delivery point requirements before commingling with other oil/emulsion receipts.
- All measured oil/emulsion receipts to the battery and the measured oil/emulsion production must be prorated against the total oil disposition of the battery.

6.2.3 Gas Batteries Producing Oil

6.2.3.1 General

All wells in the battery must be classified as gas wells.

Oil production, receipt, disposition, and inventory volumes must be reported as liquid oil. Oil volumes must not be converted to a gas equivalent volume (GEV) and must not be added to the gas volumes. If oil is recombined with the gas and delivered to a gas plant (through a gas gathering system), the oil volume as determined at the battery must be reported as a receipt of "OIL" by the gas plant. The gas plant must report the oil disposition as appropriate.

6.2.3.2 Single-well Battery

Oil/emulsion must be separated from gas and measured.

6.2.3.3 Multiwell Group Battery

Each well must have its own separation and measurement equipment, similar to a single-well battery, and its gas production must be connected by pipeline to a common location for further processing.

6.3 Base Requirements for Oil Measurement

6.3.1 System Design and Installation of Measurement Devices

The system design and installation of oil/emulsion measurement devices must be in accordance with Section 14.2, 14.3, and 14.7.

EMF systems must be designed and installed according to the requirements in Section 6.8. Any EFM system designed and installed in accordance with API MPMS, Chapter 21.2, is considered to have met the audit trail and reporting requirements, but a performance evaluation is still required in accordance with Section 14.10.

6.3.2 Volumetric Calculations

Crude oil volume measurements must be determined to a minimum of two decimal places and rounded to one decimal place for monthly reporting. Where there is more than one volume determination within the month at a reporting point, the volumes determined to two decimal places must be totalled prior to the total being rounded to one decimal place for reporting purposes.

6.3.2.1 Temperature Correction Requirements

Temperature measurement used for volume correction must be representative of the actual fluid temperature. Total monthly oil volumes for wells (production) and batteries (production, receipts, dispositions, and delivery point) must be reported in cubic metres at a standard temperature of 15°C and rounded to the nearest tenth of a cubic metre (0.1 m^3). Battery or facility opening and closing inventory volumes for monthly reporting must be rounded to the nearest 0.1 m^3 but do not require correction to 15°C. The temperature correction (Correction for the effect of Temperature on Liquids [CTL]) factor must be determined in accordance with API MPMS, Chapter 11.1.

In a proration battery, if well test oil volumes are determined by a meter, temperature compensation must be applied using one of the following methods:

- Apply a composite meter factor that incorporates a CTL factor. To arrive at a composite meter factor, divide the temperature corrected prover volume by the indicated meter volume for each prover run.
- Apply a CTL factor in real time using an electronic flow measurement system.
- Apply a CTL factor to the total test volume based on a single temperature measurement taken during the test.

See Section 14.4 for more details.

6.3.2.2 Pressure Correction Requirements

Correction to a 0.0 kPa gauge (atmospheric pressure) must be performed for continuous flow crude oil pipeline measurement where custody transfer measurement is performed.

See Section 14.5 for more details.

6.3.2.3 Shrinkage Factor

See Section 14.3 for details.

6.3.2.4 General Volume Calculations

See Section 14.9 for details.

6.3.3 Production Data Verification and Audit Trail

The field data, records, and any calculations or estimations, including EFM, relating to ERCB-required production data submitted to the PRA must be kept for inspection upon request. The reported data verification and audit trails must be in accordance with the following:

1) Test records: any records and documentation produced in the production proration testing of wells that affect measured volumes

2) Proving records: any records and documentation produced in the proving of meters and calibration of the prover and all peripheral devices (if the prover and peripheral devices are owned and operated by the licensee)

3) S&W records: any records and documentation produced in the determination of relative oil/water percentages that affect volumes

4) Delivery and receipt records: any records and documentation produced in the determination of delivery or receipt volumes

5) Estimation records: any records and documentation related to the estimation of reported volumes, including estimation methodology, record of event, and approvals

6) Tank gauging records: any records and documentation produced in the determination of reported volumes

7) Volume loss records: any records and documentation for volumes lost due to incidents such as theft, spills, and fires

8) EFM: any records and documentation (electronic, magnetic, or paper form) produced in the determination of measured volumes in accordance with the EFM requirements in Section 6.8

6.4 Field Operations

6.4.1 Production Hours

Physical well shut-ins and emergency shutdowns (ESDs) are considered downtime. Other occurrences resulting in downtime may be wax or hydrates plugging lines and some other failures. If the well has no oil production but still has gas production, it is considered to be on production. The operations personnel have to make a determination based on the operating environment in other situations when the wells are not physically shut in but may not have oil and gas production.

Oil wells operating on an on/off cycle basis, such as intermittent timers, pump-off controls, and plunger lifts, that are "operating normally and as designed on repeated cycles" and where part of the operation involves shutdown of pump equipment and/or periodic shut-in of the wells (as part of the repeated cycle) are considered on production even when the wells are not pumping or flowing.

6.4.2 Fluid Sampling Requirements for S&W Determination (and Density)

See Section 14.6 for density determination details.

6.4.3 S&W Analysis

Conduct water-cut sampling and analysis for each test.

See Section 14.8 for S&W determination details.

6.4.4 Proration Well Testing

Proration testing requirements for conventional crude oil wells are detailed in Table 6.1.

Table 6.1. Proration testing requirements for conventional crude oil wells

Class[a]					
No.	Name	Oil rate (m^3/d)	Minimum test frequency	Minimum time between tests[b] (days)	Minimum test duration[c] (hours)
1	High	> 30	3 per month[d]	5	12
2	Medium	> 6 but ≤ 30	2 per month[e]	10	22
3	Low	> 2 but ≤ 6	1 per month	15	22
4	Stripper	≤ 2	1 every quarter	45	22

[a] Classification for each well must be determined at least semiannually based on the average daily oil rate since the last assessment. If a well experiences operational changes that cause a change in the oil rate that could affect the classification, the operator must immediately change the classification. The average daily oil rate must be based on producing days (not calendar days).

[b] Minimum separation time between tests if minimum number of tests are conducted—the time between tests may be reduced if more than the minimum number of tests are conducted.

[c] Licensees should conduct longer duration tests for wells exhibiting erratic rates to obtain more representative test data.

[d] For Class 1 wells, the minimum test frequency is based on the assumption that the well is on production for the entire calendar month. The test frequency may be reduced to two per month if the well is shut in for at least 10 days within the month and to one per month if the well is shut in for at least 20 days within the month.

[e] For Class 2 wells, the minimum test frequency is based on the assumption that the well is on production for the entire calendar month. The test frequency may be reduced to one per month if the well is shut in for at least 15 days within the month.

6.4.4.1 Well Test Considerations

If there is a change in operating conditions during a test, such as due to a power failure or a change in choke setting, the test must be rejected and a new test must be conducted.

If there is insufficient or lost test data, such as due to meter failure, the test must be rejected and a new test must be conducted.

If there is a significant change in oil, gas, or water for a test, the validity of the test should be questioned and a retest should be considered.

Sufficient purge time must be allowed to ensure that liquids from the previous test are displaced by the new test well liquids.

The pressure difference between the test separator and the group line must not exceed 200 kPa.

A well test may be stopped early for operational reasons and still be considered valid. Reasons for the short test must be documented and made available to the ERCB upon request.

6.4.4.2 Common Flow Lines

For common flow lines, a well test must be conducted, with all other wells on the common flow line shut in following adequate purge time.

Combined (cascade) testing is allowed for common flow-lined wells, provided that the conditions in Section 6.7 are met. However, the combined test must be conducted first, and then the low gas producing well must be shut in to test the high gas producing well, allowing sufficient purging and stabilization time.

6.4.4.3 Field Header and Common Flow Line Purging

If a field header is located in the same building as the test separator, the test separator must be purged by allowing at least two liquid dumps to occur prior to starting the well test. The field header must clearly identify which well is tied to the header valves.

If a field header is not located in the same building as the test separator, sufficient purge time must be allowed to ensure that liquids from the previous test are replaced by the new test well liquids.

If two or more wells are tied into a common flow line, only one well must be produced during the well test, and the other well(s) must be shut in. Similar to a field header situation, sufficient purge time must be allowed to ensure that liquids from the previous production condition are replaced by the new test well liquids.

Sufficient purge time must be calculated as follows:

Purge time = Test line volume ÷ New test well liquid flow rate

Example: Calculate the minimum purge time required for the following test line:

Test line dimensions = 1500 m length, 88.9 mm OD pipe, 3.2 mm wall thickness

Previous well test flow rates = 5.5 m^3 oil/d, 12.0 m^3 water/d

Step 1

$$d = (88.9 - 3.2 \times 2) \div 1000 = 0.0825 \text{ m}$$

$$\begin{aligned}\text{Test line volume} &= (3.142 \times d^2 \times \text{length}) \div 4 \\ &= (3.142 \times (0.0825)^2 \times 1500) \div 4 \\ &= 8.02 \text{ m}^3\end{aligned}$$

Step 2

$$\text{Purge time required} = \text{Test line volume } (\text{m}^3) \div \text{Well flow rate } (\text{m}^3/\text{h})$$

$$\begin{aligned}\text{Well total liquid flow rate} &= (5.5 \text{ m}^3 + 12.0 \text{ m}^3) \div 24 \text{ h} \\ &= 0.729 \text{ m}^3/\text{h}\end{aligned}$$

$$\begin{aligned}\text{Purge time required} &= 8.02 \text{ m}^3 \div 0.729 \text{ m}^3/\text{h} \\ &= 11.0 \text{ h}\end{aligned}$$

Therefore, the minimum purge time required is 11.0 hours.

6.5 Oil Proration Battery Accounting and Reporting Requirements

Prorated production is an accounting system or procedure in which the total battery production is allocated to wells based on individual well tests. Production from multiple oil wells may be commingled before separation and continuous single-phase measurement of the components (see Figure 6.1). Individual well production must be tested periodically to determine the production rates that can be used to estimate the well's monthly production volume. The estimated monthly well production volume is corrected using a proration factor. In summary, the following must be performed (see Section 6.5.1 for details):

- test production volumes of gas (in 10^3 m^3) and oil and water (in m^3) rounded to two decimal places;
- record test duration hours to two decimal places with the nearest quarter hour as the minimum resolution;
- determine the hour production rate for each product from the well;
- determine the estimated well production by multiplying the hour rate by the monthly hours of production; and
- determine the actual (prorated) production volume by multiplying the estimated well production by the proration factor (the total actual battery production volume divided by the total estimated battery production volume).

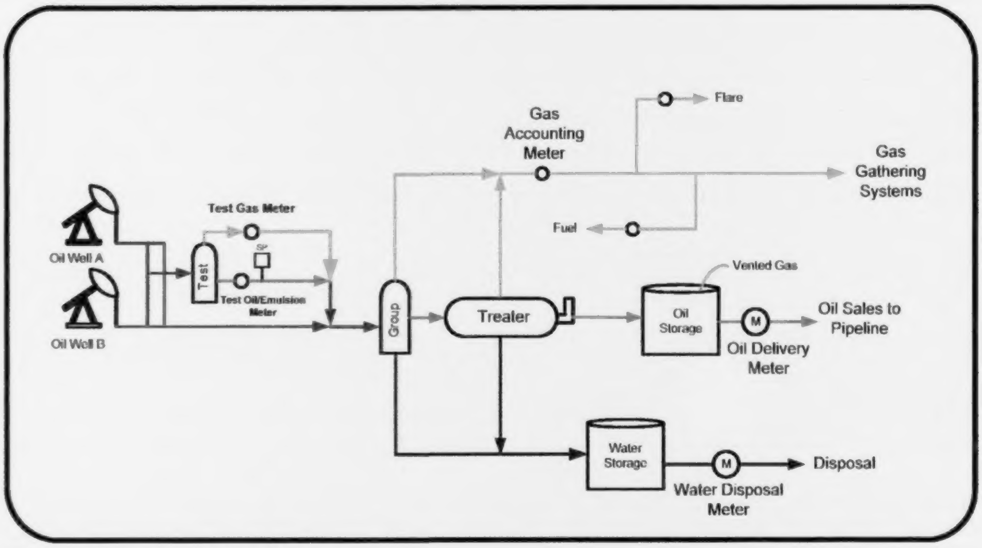

Oil Well A
Oil Well B
Test Gas Meter
Test
SP
Test Oil/Emulsion Meter
Group
Treater
Gas Accounting Meter
Flare
Gas Gathering Systems
Fuel
Vented Gas
Oil Storage
M
Oil Delivery Meter
Oil Sales to Pipeline
Water Storage
M
Water Disposal Meter
Disposal

Figure 6.1. Proration testing battery

The minimum test frequency and duration requirements (see Table 6.1) apply to all conventional oil wells under primary production and waterflood operations included in proration batteries.

Monitoring the performance of miscible floods and other enhanced oil recovery schemes usually requires testing criteria other than rate alone; therefore, testing requirements for miscible flood schemes are set out in each scheme approval.

Licensees must monitor the classification for wells producing to a battery and meet the required testing frequency and duration for each well (see Table 6.1). Some latitude to the classifications is allowed. For example, considering all wells producing to a battery or satellite as a lower rate class would be considered appropriate if a small proportion of the wells only marginally exceeded the upper limit of that classification.

Many low-rate and stripper wells exhibit erratic production rates due to high water-oil ratios or gas-oil ratios, and oversized production lines and test separators can make accurate measurement difficult. Longer test duration can improve test accuracy for many of these wells. To allow licensees the opportunity to conduct longer duration tests, class 3 and 4 wells are allowed to use up to an eight-day cycle chart drive for measurement of test gas production volumes.

The use of automatic well testing equipment and procedures with EFM provides licensees the opportunity to conduct tests of shorter durations than specified in Table 6.1. The automation computer can monitor the test and use statistical calculation methods to ensure that a representative rate is obtained prior to terminating the test. This practice is acceptable when

- the accumulated oil test volume is polled at a frequency of at least once per hour,
- the criteria for stabilization ensures that the uncertainty for the monthly well oil volume does not exceed half of the maximum uncertainty of monthly volume stipulated in Section 1, and
- the computer program is properly documented and available to the ERCB upon request.

The test-to-test method, whereby data from a test are used to estimate production until the next test is conducted, must be used to estimate the production volume from each oil well based on the test rate and the total production hours. This production estimation method and the proration methodology are outlined below. A licensee may use its own worksheet format, provided that the required data are retained and available to the ERCB upon request.

6.5.1 Proration Estimated Volume Calculation

Calculate the estimated production of each well from the test data using the sample worksheet on the next page.

1) Calculate the test rate/hour for crude oil, gas, and water:

   Rate per hour = Test production volume (including GIS volumes for gas) ÷ Test duration (hr)

   Enter the test rate/hour rounded to four decimal places.

2) Calculate the hours of production for each test rate during the reporting month. Include only the hours of prorated production:

   a) hours of production from the first day of the month to the start of the first test for the month—data from the last test conducted during the previous month will be used to estimate production until the first test for the month is conducted, and

   b) hours of production from the start of each test conducted during the month up to the start of the next test, or the end of the month, whichever is applicable.

   Enter the hours produced rounded to the nearest hour.

3) Calculate the estimated production of oil, gas, and water for the production hours applicable to each test rate:

   Estimated production = Test rate/hour x Hours produced

Enter the estimated production of oil, gas, and water rounded to one decimal place.

4) Calculate the totals for each well:

   Add the hours produced that are applicable to each test rate and enter the total.

   Add the estimated production of oil, gas, and water, and enter the totals.

   Note that if a GOR is used to estimate the well gas production in accordance with Section 4.3.5:

   Estimated well gas production = Estimated well oil production x GOR

UID	AB WI 100060100101W400					**Test duration[c]**	**Hourly test rate**				**Estimated production**		
	Test date		**Test oil**	**Test gas**	**Test water**		**Oil**	**Gas**	**Water**	**Prod**	**Oil**	**Gas**	**Water**
Vessel	**dd**	**mm**	**m^3**	**$10^3\ m^3$**	**m^3**	**hours**	**m^3/hr**	**$10^3\ m^3/hr$**	**m^3/hr**	**hours**	**m^3**	**$10^3\ m^3$**	**m^3**
Prior mo.	25	6	9.05	1.35	3.53	24.00	0.3771	0.0563	0.1471	96	36.2	5.4	14.1
	5	7	8.85	1.28	3.26	24.00	0.3688	0.0533	0.1358	168	62.0	9.0	22.8
	12	7	9.40	1.51	2.98	24.00	0.3917	0.0629	0.1242	216	84.6	13.6	26.8
	21	7	9.15	1.67	3.65	24.00	0.3813	0.0696	0.1521	264	100.7	18.4	40.2
									Totals	**744**	**283.5**	**46.4**	**103.9**

UID	AB WI 100080100101W400					**Test duration[c]**	**Hourly test rate**				**Estimated production**		
	Test date		**Test oil**	**Test gas**	**Test water**		**Oil**	**Gas**	**Water**	**Prod**	**Oil**	**Gas**	**Water**
Vessel	**dd**	**mm**	**m^3**	**$10^3\ m^3$**	**m^3**	**hours**	**m^3/hr**	**$10^3\ m^3/hr$**	**m^3/hr**	**hours**	**m^3**	**$10^3\ m^3$**	**m^3**
Prior mo.	28	6	5.05	0.95	4.15	24.00	0.2104	0.0396	0.1729	48	10.1	1.9	8.3
	[a]3	7	5.85	1.25	4.50	48.00	0.2406	0.0490	0.1792	336	80.8	16.5	60.2
	[a]4	7	5.70	1.10	4.10								
	17	7	6.01	1.15	5.00	25.50	0.2357	0.0451	0.1961	168	39.6	7.6	32.9
	24	7	5.40	0.99	4.10	22.75	0.2374	0.0435	0.1802	192	45.6	8.4	34.6
									Totals	**744**	**176.1**	**34.4**	**136.0**

UID	AB WI 100160100101W400					**Test duration[c]**	**Hourly test rate**				**Estimated production**		
	Test date		**Test oil**	**Test gas**	**Test water**		**Oil**	**Gas**	**Water**	**Prod**	**Oil**	**Gas**	**Water**
Vessel	**dd**	**mm**	**m^3**	**$10^3\ m^3$**	**m^3**	**hours**	**m^3/hr**	**$10^3\ m^3/hr$**	**m^3/hr**	**hours**	**m^3**	**$10^3\ m^3$**	**m^3**
Prior mo.	1[b]	7	1.80	1.10	2.20	24.00	0.0750	0.0458	0.0917	24	1.8	1.1	2.2
	2[b]	7	4.00	2.00	5.00	24.00	0.1667	0.0833	0.2083	120	20.0	10.0	25.0
	7	7	3.95	1.95	4.95	23.00	0.1717	0.0848	0.2152	288	49.4	24.4	62.0
	19	7	4.25	2.05	5.05	26.00	0.1635	0.0788	0.1942	216	35.3	17.0	41.9
	28	7	5.65	2.00	5.50	27.75	0.2036	0.0721	0.1982	96	19.5	6.9	19.0
									Totals	**744**	**126.0**	**59.4**	**150.1**

Note that test gas volumes must include gas-in-solution (GIS) volumes (see Section 4.3.5).

[a] Tests on July 3 and 4 were comparable and consecutive (i.e., there were no operational changes). Therefore, the results are combined and used as one 48-hour test.

[b] Tests on July 1 and 2 were not comparable due to operational changes (e.g., choke/pump speed). Therefore, they are used as separate 24-hour tests.

[c] Test duration must be reported to the nearest quarter hour as the minimum resolution (record hours to two decimal places, e.g., 2 hr and 45 min are entered as 2.75 hr).

6.5.2 Calculate Proration Factors and Monthly Production

1) Calculate the total estimated battery production for oil, gas, and water:

   Total estimated battery production = Sum of all the wells' total estimated production

2) Calculate the total actual battery production and proration factors for oil, gas, and water:

   For oil and water,

   Total actual battery production = Total monthly disposition + Closing inventory – Opening inventory – Total receipts

   For gas,

   Total actual battery production = Total monthly disposition (sales, fuel, flare, vent) – Total receipts

   Proration factor = Total actual battery production ÷ Total estimated battery production

   The proration factors for oil, gas, and water must be rounded to five decimal places.

   Note that if a GOR is used to estimate the total battery gas production volume in accordance with Section 4.3.5:

   Estimated battery gas production = Actual battery oil production x GOR

   Estimated battery gas production = Actual battery gas production

   Gas proration factor = 1.00000

3) Calculate each well's monthly prorated production volumes for oil, gas, and water:

   Monthly prorated oil volume = Well estimated oil production x Oil proration factor

   Monthly prorated gas volume = Well estimated gas production x Gas proration factor

   Monthly prorated water volume = Well estimated water production x Water proration factor

4) Check that total well production equals total actual battery production for oil, gas, and water. If the volumes are not equal due to rounding, minor adjustments to the monthly volumes may be required.

   Sum of prorated well production = Total actual battery production

6.6 Condensate Receipts at an Oil Battery

If condensate that could be flashed into the gas phase is received by pipeline at an oil battery, the licensee must choose from the applicable condensate reporting options in Section 5.5.

If condensate received from an external source will be reported as a GEV, that volume must be subtracted from the total monthly battery gas disposition volume to determine the monthly battery gas production volume.

If condensate that could be flashed off into the gas phase is trucked to an oil battery, the licensee must report it as below:

- If condensate received into the battery is ≤ 2.0 m^3/day and/or $\leq 5\%$ of the battery oil production, the condensate can be reported as all liquid condensate or as a GEV.

- If condensate received into the battery is > 2.0 m^3/day and/or > 5% of the battery oil production, the licensee must report flashed condensate as a GEV receipt volume and unflashed condensate as a liquid condensate receipt.

Note that this may also be applicable to other light hydrocarbons delivered into an oil battery.

6.7 Combined (Cascade) Testing

When a prorated oil well has such low gas production that it cannot properly operate test equipment, a licensee may test two wells simultaneously—combined (cascade) test—through the same test separator. In such cases, the following procedure must be followed:

1) Establish oil, gas, and water production volumes for a high gas producing well by testing it individually through the test separator.
2) Conduct a test for both the high gas producing well and a low gas producing well together through the same test separator immediately after testing the high gas producing well, allowing time for stabilization. (The testing sequence may be reversed with the testing of the combined wells first.)
3) The operating condition of both wells must not be changed. If it is, a new set of tests is required.
4) Total test oil, gas, and water volumes determined for the combined (cascade) test minus the test oil, gas, and water volumes for the high gas producing well will be the test volumes for the low gas producing well (see example below).
5) Both wells should have similar S&W percentages. If any of the calculated oil, gas, or water volumes for the low gas producing well are negative, the tests are not valid and both tests must be repeated.

The use of combined (cascade) testing does not require special approval from the ERCB.

Example
Well A = High gas producing
Well B = Low gas producing

Test Results

Well	Test date	Oil (m^3)	Gas (10^3 m^3)	Water (m^3)
Well A + B	July 4	80.0	20.0	20.0
Well A	July 5	50.0	19.0	12.0
Well B = (Well A + B - Well A)	**July 4**	**30.0**	**1.0**	**8.0**

6.8 Electronic Flow Measurement for Oil Systems

See Section 14.10 for details.

6.9 Reporting Requirements and Scenarios Based on Alberta Energy Royalty Regimes for Wells Producing Oil

Below are the required reporting scenarios for both oil wells and gas wells producing oil. Note that the cases in Alberta Energy *IL 87-3: ERCB Reporting Requirements and Department of Energy Royalty Regimes for Wells Producing Oil, Field Condensate, or Pentanes Plus* have been transferred to this directive. If the case number in this directive is different from what was in *IL 87-3*, the equivalent case number is noted. See Section 13 for condensate cases.

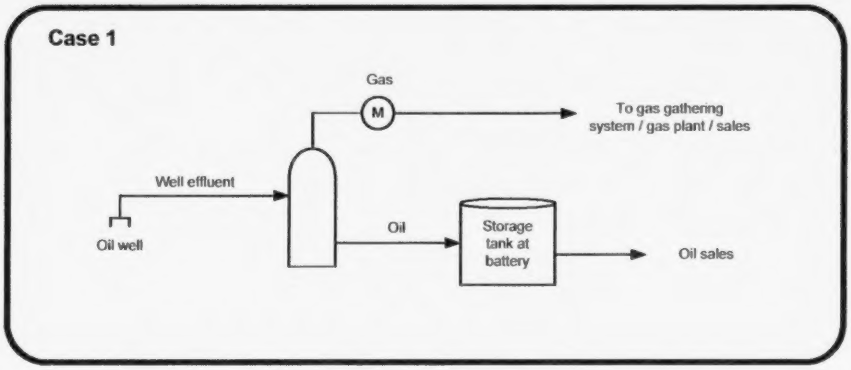
6.9.1 ERCB Classification—Oil Wells

Case 1

Oil separated from well effluent and sold from battery facilities.

Report as OIL PROD and OIL DISP at the ABBT in the PRA.

Royalties: *Petroleum Royalty Regulations* for oil.

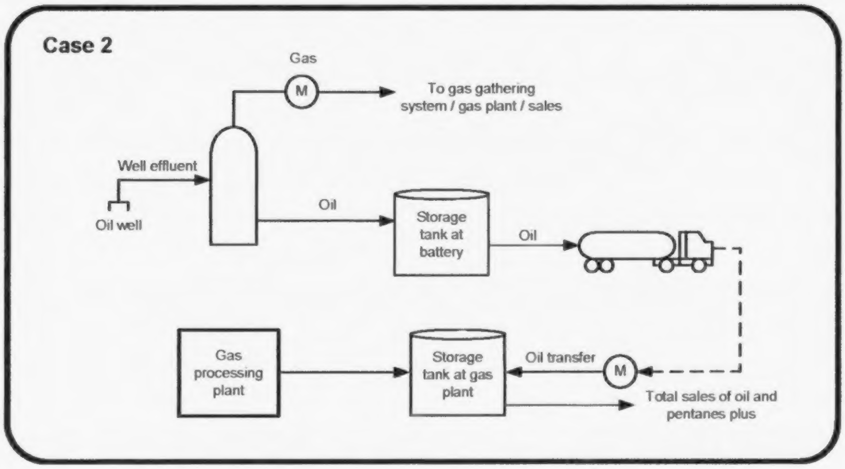

Case 1
Gas
M
To gas gathering system / gas plant / sales
Well effluent
Oil well
Oil
Storage tank at battery
Oil sales

Case 2

Oil separated from well effluent, measured, and trucked to a tank at the gas plant.

Report as OIL PROD and OIL DISP at ABBT and OIL REC at the ABGP in the PRA.

Royalties: *Petroleum Royalty Regulations* for oil and *Natural Gas Royalty Regulations* for pentanes plus.


Case 2
Gas
M
To gas gathering system / gas plant / sales
Well effluent
Oil well
Oil
Storage tank at battery
Oil
Gas processing plant
Storage tank at gas plant
Oil transfer
M
Total sales of oil and pentanes plus

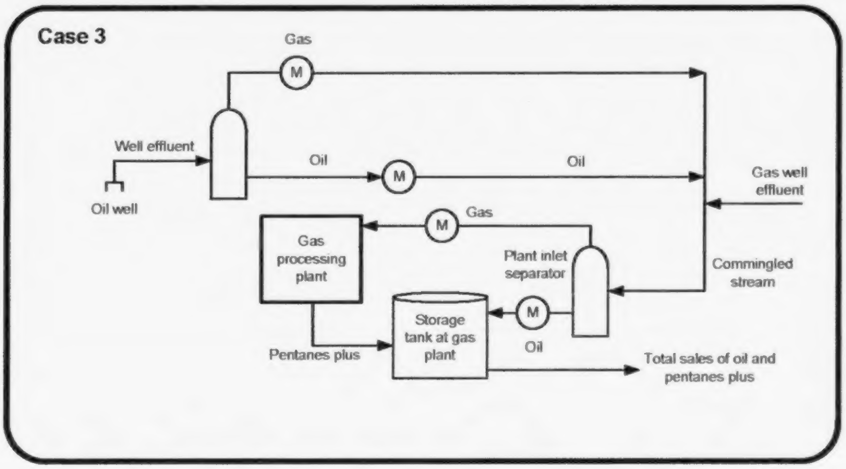
Case 3

Oil separated from well effluent, measured, commingled with gas, and sent to a gas plant.

Report as OIL PROD and OIL DISP at ABBT and OIL REC at the ABGP in the PRA. Shipments reported at the gas plant will be the total combined sales of this transferred oil and the plant pentanes plus products.

Note: The total plant inlet volumes reported would normally include the gas equivalent of the inlet condensate, but in this case, the inlet condensate volumes used to calculate the total plant inlet must be the net of the oil production that has been transferred to the plant. The reported plant inlet volumes and the pentanes plus production will be the measured volumes less this transferred oil production.

Royalties: *Petroleum Royalty Regulations* for oil and *Natural Gas Royalty Regulations* for pentanes plus.

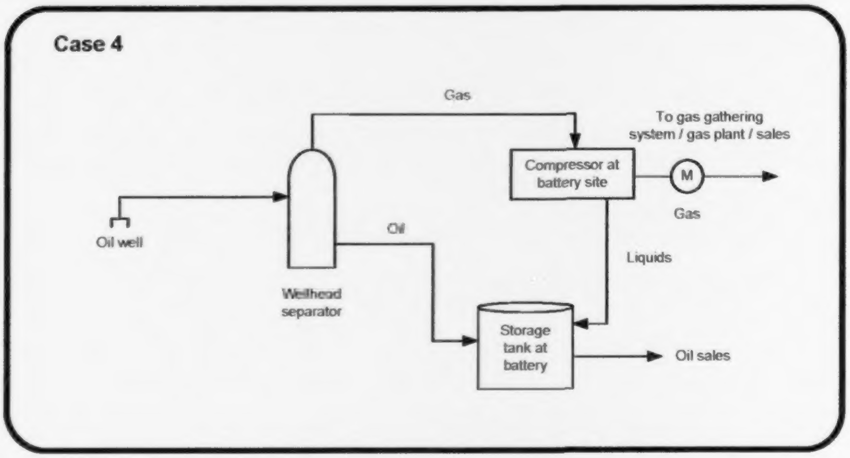

Case 3
Gas
M
Well effluent
Oil
M
Oil
Gas well effluent
Oil well
M
Gas
Gas processing plant
Plant inlet separator
Commingled stream
Storage tank at gas plant
M
Oil
Pentanes plus
Total sales of oil and pentanes plus

Case 4

Oil separated from well effluent at battery, gas compressed as part of normal battery operations, and additional liquids recovered as a result of compression and commingled with battery oil production.

Report total fluid as OIL PROD and prorate to wells in the ABBT and total OIL DISP in the PRA.

Royalties: *Petroleum Royalty Regulations* for oil.

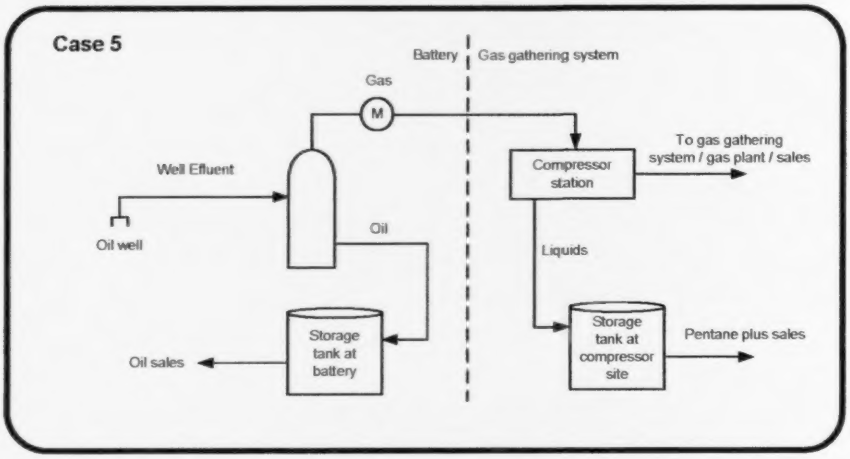

Case 4
Gas
To gas gathering system / gas plant / sales
Compressor at battery site
M
Gas
Oil well
Oil
Liquids
Wellhead separator
Storage tank at battery
Oil sales

Case 5

Oil separated from well effluent at battery, gas compressed not as part of normal battery operations, and additional liquids recovered as a result of compression.

Report total OIL PROD and total OIL DISP at the ABBT on PRA. Hydrocarbon liquids recovered as a result of compression will be reported as pentanes plus at the gathering system (GS) in the PRA.

Royalties: *Petroleum Royalty Regulations* for oil.


Case 5
Battery
Gas gathering system
Gas
M
To gas gathering system / gas plant / sales
Well Effluent
Compressor station
Oil
Oil well
Liquids
Storage tank at battery
Oil sales
Storage tank at compressor site
Pentane plus sales

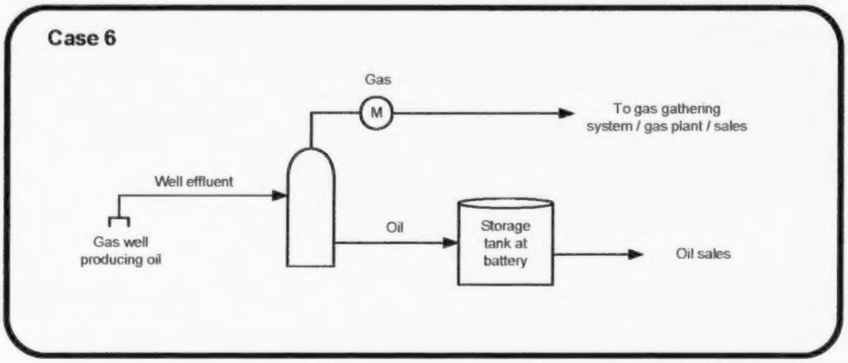
6.9.2 ERCB Classification—Gas Well Producing Oil

Case 6 (Same as Case 10 in *IL 87-3*)

Oil separated from well effluent, measured, and sold from battery.

Report as OIL PROD and OIL DISP at the ABBT in the PRA.

Royalties: *Petroleum Royalty Regulations* for oil.


Case 6
Gas
M
To gas gathering system / gas plant / sales
Well effluent
Gas well producing oil
Oil
Storage tank at battery
Oil sales

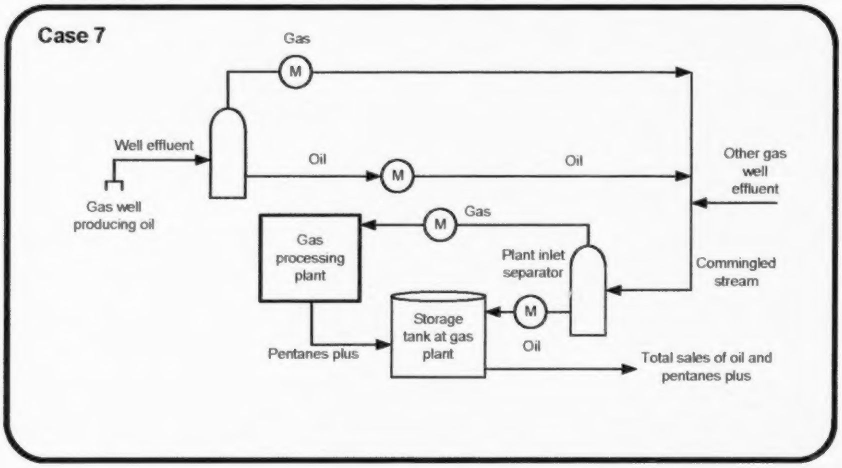
Case 7 (Same as Case 11 in *IL 87-3*)

Oil separated from well effluent, measured, commingled with gas, and sent to a gas plant.

Report as OIL PROD and OIL DISP at ABBT and OIL REC at the ABGP in the PRA. Shipments reported at the gas plant will be the total combined sales of this transferred oil and the plant pentanes plus products.

Note: The total plant inlet volumes reported would normally include the gas equivalent of the inlet condensate, but in this case, the inlet condensate volumes used to calculate the total plant inlet must be the net of the oil production that has been transferred to the plant. The reported plant inlet volumes and the pentanes plus production will be the measured volumes less this transferred oil production.

Royalties: *Petroleum Royalty Regulations* for oil and *Natural Gas Royalty Regulations* for pentanes plus.

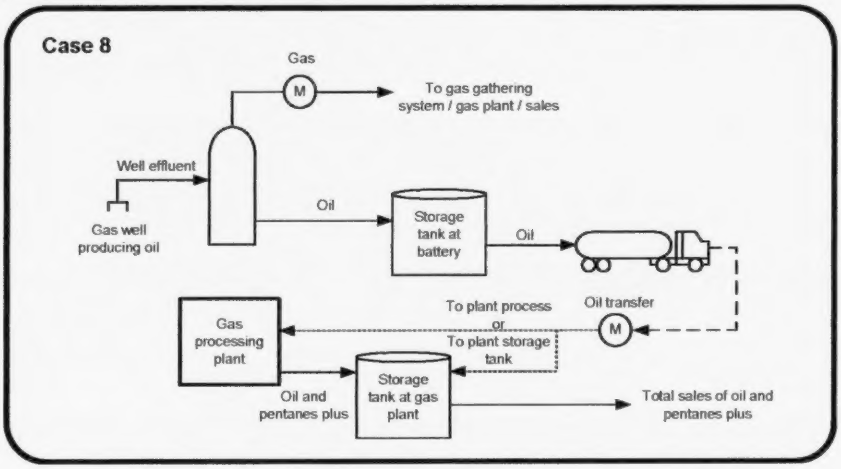

Case 7
Gas
M
Well effluent
Oil
M
Oil
Other gas well effluent
Gas well producing oil
M
Gas
Gas processing plant
Plant inlet separator
Commingled stream
Storage tank at gas plant
M
Oil
Pentanes plus
Total sales of oil and pentanes plus

Case 8 (Same as Case 12 in *IL 87-3*)

Oil separated from well effluent, measured, and trucked to a gas plant process or a storage tank at the gas plant.

Report as OIL PROD and OIL DISP at ABBT and OIL REC at the ABGP in the PRA. Shipments reported at the gas plant will be the total combined sales of this transferred oil and the plant pentanes plus products.

Royalties: *Petroleum Royalty Regulations* for oil and *Natural Gas Royalty Regulations* for pentanes plus.


Case 8
Gas
M
To gas gathering system / gas plant / sales
Well effluent
Gas well producing oil
Oil
Storage tank at battery
Oil
Oil transfer
M
To plant process or To plant storage tank
Gas processing plant
Storage tank at gas plant
Oil and pentanes plus
Total sales of oil and pentanes plus

7 Gas Proration Batteries

This section presents the requirements and exceptions relating to measurement, accounting, and reporting for gas proration batteries.

Gas well operators have the option of not measuring the gas and/or separated liquids at each well site. If the gas and liquids are not separated and measured, they can be prorated. Operators that decide to install prorated systems in accordance with the provisions of this section are accepting higher uncertainty at the wellhead, offset by lower capital and operating costs.

Prorated wells are tested periodically to determine the typical flow rate. The gas and liquids from a number of wells are measured at a group meter, and the volume at the group meter is prorated back to the individual wells based on the most recent test and the hours on stream.

The measurement uncertainty assigned to individual wells within gas proration batteries is greater than for wells where the gas is separated and measured. For this reason, operators should understand the impact of this type of measurement when dealing with partners and third parties.

Prorated wells can be tied in to the same system as measured wells but under separate battery codes. In these cases, the measured wells are kept whole, and the difference between the battery disposition and the measured well volume is prorated to all the proration wells. This is referred to as measurement by difference (see Section 5.5), since the measured volume is subtracted from the group measurement before proration. Measurement by difference increases the uncertainty of the prorated well volume estimate.

7.1 General Requirements

The three types of gas proration batteries allowed in Alberta are

- gas multiwell proration SE Alberta batteries (PRA subtype 363),
- gas multiwell proration outside SE Alberta batteries (PRA subtype 364), and
- gas multiwell effluent measurement batteries (PRA subtype 362).

All wells in a gas proration battery must be classified as gas wells and must be connected by flow line to a common group separation and measurement point.

All gas proration batteries require periodic well tests to be conducted to determine production rates, production ratios, and/or ECF that will be used in the determination of monthly estimated well production volumes. Monthly estimated well production volumes are multiplied by proration factors to determine the actual well production volumes for reporting purposes. All wells must be tested annually unless otherwise stated in this section.

All volumetric calculations must be to the required decimal places listed below.

Table 7.1. **Required decimal places for volumetric calculations in gas proration batteries**

Type of calculations	Number of decimals to be calculated to	Number of decimals to be rounded to
Productions and estimated productions	2	1
Well test gas, GEV of test condensate, test condensate, or test water	3	2
WGR, condensate-gas ratio (CGR), and oil-gas ratio (OGR)	5	4
Proration factors, ECF	6	5

Test taps must be installed at all proration gas wells. The required test tap locations are specified below for each of the above batteries.

See Section 8 of this directive for sampling and analysis of gas, condensate, and water.

7.1.1 Group Measurement

All gas proration batteries require continuous single-phase measurement of total monthly battery gas, condensate, and water production volumes at the group measurement point. If liquid condensate is trucked out of the group separation and measurement point to a gas plant for further processing, the condensate must be reported as a GEV from the battery, through the gas gathering system, to the gas plant.

Gas wells in any one of the three types of proration batteries must not be commingled with "measured" gas sources or gas from another proration battery without group measurement, or with gas wells in a different type of gas proration battery, upstream of their respective group measurement points. Variances from this requirement may be allowed if the "Exception" criteria in Section 5.5 are met or if site-specific approval has been obtained from the ERCB prior to implementation.

7.1.2 Stabilized Flow and Representative Flow

The words stabilized flow and representative flow are used extensively in this section as defined below.

Stabilized flow indicates a point at which flowing parameters of gas, condensate, or water are producing under normal operating conditions and represent production levels equal to the well's normal average flow rate. Stabilized flow can only be achieved when all testing equipment associated in determining an actual volume has reached equilibrium (i.e., liquid levels in test separator, pressure and temperature stabilization to normal operating conditions).

Representative flow can be used when stabilized flow is not achievable, such as for wells with artificial lift systems and wells with slugging characteristics. The test volumes of gas, condensate, or water must be representative of the well's production capability under normal operating conditions.

Wells that use artificial lift systems or characteristically display slug flow must be tested for a minimum duration that completes multiple flow cycles to accurately determine a representative volume of gas, condensate, or water. These representative production volumes are then extrapolated to accurately reflect the wells' production over an extended period of time.

7.2 Gas Multiwell Proration SE Alberta Batteries

Gas wells in this type of battery do not require dedicated continuous measurement for each well or special approvals from the ERCB.

Production rates determined during a well test must be used in the estimation/proration calculations within 30 days of the test until the next test is conducted.

Total battery gas production must be measured and prorated back to the individual wells, based on each well's estimated monthly gas production. Estimated well gas production is based on hourly production rates, determined by periodic well tests and monthly producing hours.

Gas wells that produce from shallow gas zones in SE Alberta may be included in these types of batteries. The zones include coals and shales from the top of the Edmonton Group to the base of the Colorado Group. The production from two or more of these zones without segregation in the wellbore requires either prior approval from the ERCB for commingled production, which has been granted in a portion of SE Alberta in Order No. MU 7490, or adherence to the self-declared commingled production requirements described in *Directive 065: Resources Applications for Oil and Gas Reservoirs*.

7.2.1 Group Measurement

Group measured production is generally determined through individually measured product streams. A minimum of two-phase group measurement is required because the battery water production must be reported at the battery level. This group measurement point is located generally at the battery site where a compressor is present (see Figure 7.1).

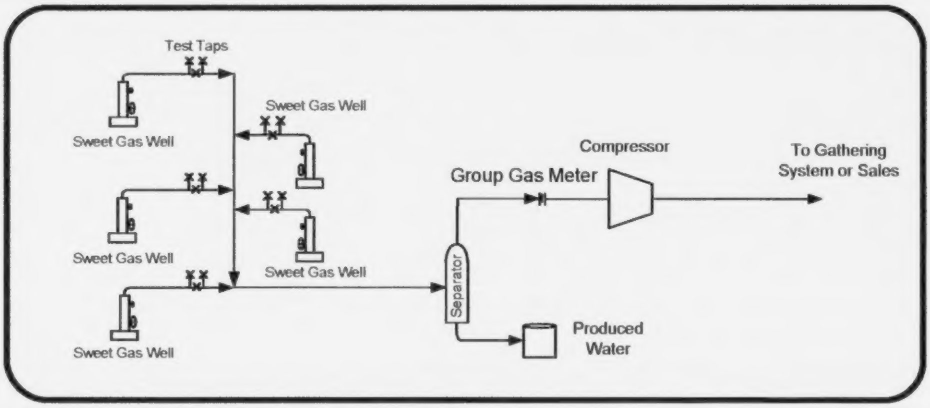


Figure 7.1. Typical SE Alberta shallow gas battery

7.2.2 Size of a SE Alberta Multiwell Gas Proration Battery

There is no limit on the number of flow-lined wells that may be in a SE Alberta shallow gas proration battery; however, licensees are encouraged to consider the logistics of the battery's operation in determining the size of these batteries, with the key factors being

- the ability to conduct representative well tests at the minimum frequency specified below, and
- the configuration and operating pressures of the battery and flow lines such that all wells can readily flow.

This approach will generally result in the main pipeline system laterals being used to establish a group measurement point.

7.2.3 Testing Requirements

Gas production rate tests must be conducted for each well in the battery in accordance with the following requirements:

- The test must be of sufficient duration to clearly establish a stabilized flow rate.
- The test must be representative of the well's capability under normal operating conditions.
- Testing programs and procedures must ensure that all wells are treated equitably within their respective batteries. These types of wells are typically tested by directing flow from the well through a test meter; however, a test separator system could also be used.
- New wells must be tested within the first 30 days of production, then again within 12 months, and thereafter according to Table 7.2.

If these requirements cannot be satisfied, the operator must either reconfigure the system (e.g., redirect some wells to another battery/group measurement point) or test each of the individual wells within the battery once per month.

Table 7.2. Testing frequency for SE Alberta shallow gas wells

Minimum rate	Maximum rate	Number of tests	Frequency*
	≤0.5 10^3 m^3/d	1	Triennial
>0.5 10^3 m^3/d	≤5.0 10^3 m^3/d	1	Biennial
>5.0 10^3 m^3/d		1	Annual

*See Section 2.3 for frequency definition.

7.2.4 Production Accounting and Reporting Procedures

Water Reporting Requirements

The reporting of water production for the qualified wells in SE Alberta shallow gas batteries is not required. However, all water receipts and disposition must be reported at the battery level. The water must be properly stored in accordance with ERCB *Directive 055* requirements. An "ABMC" receipt code can be used to balance the disposition at the battery level on the PRA. If the water is trucked to non-PRA reporting facilities without a reporting code or evaporated on site, it must be reported using an "ABMC" disposition code.

Production Volume Calculations

Monthly gas production volumes are to be calculated as follows:

1) Calculate well gas test rate:

Well gas test rate (10^3 m^3/hour) = Well test gas volume (10^3 m^3) / Well test duration (hours)

2) Calculate estimated monthly well gas volume:

Estimated monthly well gas volume = Well gas test rate x Monthly total hours of well production

3) Calculate total estimated gas production for the battery:

Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

4) Calculate proration factor for gas:

Gas proration factor = Total battery measured monthly gas volume / Total battery estimated monthly gas volume

5) Calculate actual monthly (prorated) well gas production:

Actual monthly well gas production = Gas proration factor x Estimated monthly well gas volume

7.3 Gas Multiwell Proration Outside SE Alberta Batteries

Gas wells in this type of battery do not require dedicated continuous measurement for each well. Production rates, WGRs, and/or CGRs determined during a well test must be used as soon as reasonably possible in the estimation/proration calculations until the next test is conducted.

Total battery gas production must be measured and prorated back to the individual wells based on each well's estimated monthly gas production. Estimated well gas production is based on hourly production rates, determined by periodic well tests and monthly producing hours.

Total battery condensate production must be measured if present. If it is delivered for sale from the battery, it must be prorated back to the individual wells based on each well's CGR from the production tests. The sales condensate must be reported as a liquid disposition on the PRA. Then the estimated gas production volume at each well will not include the GEV of the condensate. If the condensate is recombined with the gas for further processing to a gas plant, the condensate must be reported as a GEV and added to the measured gas production volume and reported on the PRA.

Total battery water production must be measured and prorated back to the individual wells based on each well's estimated monthly water production. Estimated well water production is based on a WGR, determined by periodic well tests multiplied by the estimated monthly well gas production (see Figure 7.2).

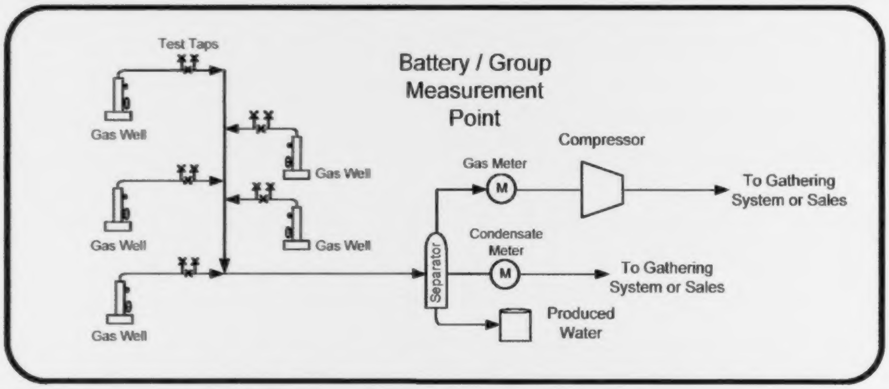


Figure 7.2. Typical outside SE Alberta multiwell gas proration battery

If total water production at each well in the battery is less than or equal to 0.50 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion, water production may be prorated to all wells in the battery based on the estimated gas production at each well. If a group of new wells not previously on production is to be configured as a proration battery, the qualifying flow rates must be based on production tests conducted under the normal operating conditions of the proration battery.

There is no geographical or zonal limitation for this type of proration battery. The "Exception" criteria in Section 5.4 must be met or ERCB site-specific approval must be obtained prior to the proration battery implementation either at the initial design and installation stage or at a later stage of production when the production rate decreases to a point that continuous measurement is not economical.

Gas wells classified as producing oil rather than condensate must not be tied into a gas multiwell proration outside SE Alberta battery unless the well oil and gas production volumes are separated and measured prior to commingling with the other wells in the battery and either the "Exception" criteria in Section 5.5 are met or site-specific approval has been obtained from the ERCB prior to implementation. However, if a gas well classified as producing condensate in a gas multiwell proration outside SE Alberta battery is reclassified by the ERCB as producing oil, the well may remain in the battery provided that the well is equipped with a separator and there is continuous measurement of the gas, oil, and water or, alternatively, the measurement, accounting, and reporting procedures specified in Section 7.3.2.1 are followed.

7.3.1 Well Testing Requirements

Well testing is typically performed by directing well production through a three-phase portable test separator configured with dedicated meters for gas, condensate, and water. Test equipment using two-phase separation is acceptable if hydrocarbon liquids are too small to be measured during typical well test durations. Other options that provide equivalent liquid volume determination accuracy may also be considered. For example, if a three-phase separator is not available, alternative equipment, such as a two-phase separator with a total liquid meter and continuous water cut analyzer, may be acceptable (see Figures 7.3 and 7.4).

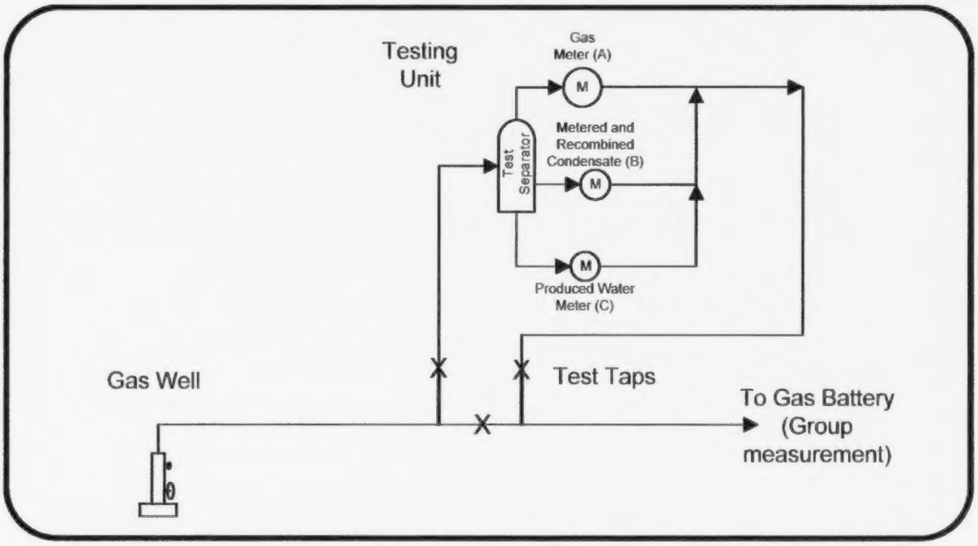


Figure 7.3. Typical testing unit for gas multiwell proration outside SE Alberta battery

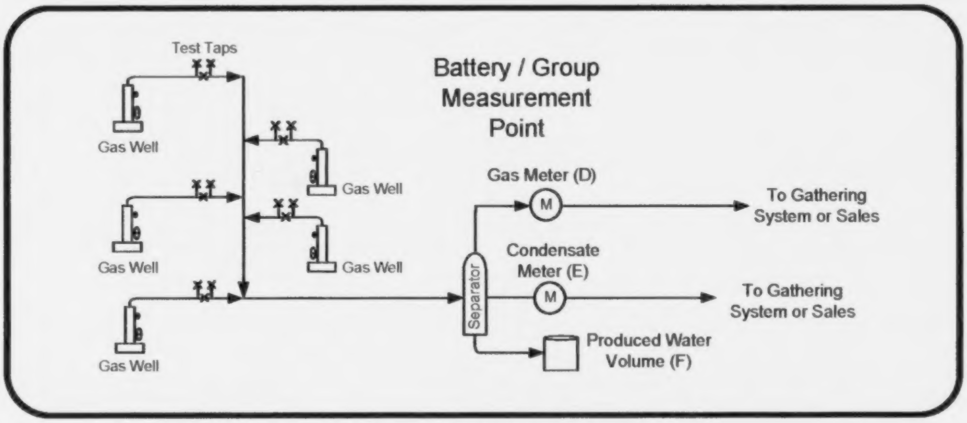

Test Taps
Battery / Group Measurement Point
Gas Well
Gas Well
Gas Well
Gas Well
Gas Well
Gas Meter (D)
M
To Gathering System or Sales
Separator
Condensate Meter (E)
M
To Gathering System or Sales
Produced Water Volume (F)

Figure 7.4. Typical gas multiwell proration outside SE Alberta battery

Test frequency may be extended with ERCB approval.

Unless alternative test procedures have been specified in an ERCB approval, the test must be conducted with measurement of all phases as follows:

- The test must begin only after a liquid level stabilization period.
- The test duration must be a minimum of 12 hours.
- After the commencement of production at the proration battery, all wells must be tested within the first month, then again within six months, and thereafter annually. New wells added to the battery at some future date must be tested within the first month of production, then again within six months, and thereafter annually.
- Consistent testing procedures must be used for consecutive tests to identify if a change in a well's flow characteristics has occurred.
- These wells are typically tested by directing flow from the well through a test separator. If the initial testing with a separator shows a liquid-gas ratio (LGR) of less than 0.01 m^3 liquid/10^3 m^3 gas, other testing methodology, such as a smaller separator or a single test meter without separation, could be used for the next test. If the total liquid volumes at group measurement point exceed a ratio of 0.05 m^3 liquid/10^3 m^3 gas in any month, a test separator must be used to test all the wells within the battery for the next round of testing to determine where the liquid originated.
- The gas, condensate, and water volumes must be measured.
- The condensate must be sampled during every test and subjected to a compositional analysis, which is to be used to determine the gas equivalent factor (GEF). The sample may be taken from the condensate leg of a three-phase separator or the liquid leg of a two-phase separator. (The water must be removed from the condensate before conducting the analysis.)
- The GEF must be used to convert the liquid condensate volume determined during the test to a GEV, which will be added to the measured test gas volume to determine the total test gas volume if the condensate is not delivered for sale at the group measurement point (see Section 7.3.2).

- The WGR, CGR, and OGR (if applicable) must be determined by dividing the test water, condensate, and oil volume respectively by the total test gas volume.
- For orifice meters, the test gas meter must use 24-hour charts for a test period of 72 hours or less, unless electronic flow measurement is used; for testing periods longer than 72 hours, 7-day charts may be used, provided that good, readable pen traces are maintained (see Section 4.3.4).

7.3.2 Production Volume Calculations

Monthly production volumes are to be calculated as follows:

Units: All gas volumes and GEV are to be in 10^3 m^3 and liquid volumes in m^3.

1) Calculate well gas test rate (see Figure 7.3):

   Well gas test rate (10^3 m^3/hour) = (Well test gas volume [A] + GEV of well test condensate [B]) / Well test hours

   Note: Do not include GEV of [B] if condensate is delivered for sale at the group measurement point.

2) Calculate estimated monthly well gas volume:

   Estimated monthly well gas volume = Well gas test rate x Monthly total hours of well production

3) Calculate total estimated gas production for the battery:

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

4) Calculate the well WGR (see Figure 7.3):

   WGR = Well test water volume (C) / (Well test gas volume [A] + GEV of well test condensate [B])

   Note: Do not include GEV of [B] if condensate is delivered for sale at the group measurement point.

5) Calculate estimated water production for each well:

   Estimated monthly well water volume = Estimated monthly well gas volume x WGR

6) Calculate total estimated water production for the battery:

   Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

If the condensate is delivered for sale at the group measurement point, calculate the next two items; otherwise go directly to item 9.

7) Calculate the well CGR (see Figure 7.3):

   CGR = Well test condensate volume (B) / Well test gas volume (A)

8) Calculate estimated condensate production for each well:

   Estimated monthly well condensate volume = Estimated monthly well gas volume x CGR

9) Calculate total estimated condensate production for the battery:

   Total battery estimated monthly condensate volume = Sum of all estimated monthly well condensate volumes

10) Calculate proration factors for gas, condensate (if delivered for sale), and water (see Figure 7.4):

Gas Proration Factor (GPF) = (Total battery measured monthly gas volume [D] + GEV of total battery condensate [E]) / Total battery estimated monthly gas volume

Note: Do not include GEV of [E] if condensate is delivered for sale at the group measurement point.

Water Proration Factor (WPF) = Total battery actual monthly water volume (F) / Total battery estimated monthly water volume

Condensate Proration Factor (CPF) = Total battery measured monthly condensate volume [E] / Total battery estimated monthly condensate volume

11) Calculate actual monthly (prorated) well production:

Actual monthly well gas production = Estimated monthly well gas volume x GPF

Actual monthly well water production = Estimated monthly well water volume x WPF

Actual monthly well condensate production = Estimated monthly well condensate volume x CPF

7.3.3 Exception

If a gas well classified as producing condensate in a gas multiwell proration outside SE Alberta battery is reclassified by the ERCB as a gas well producing oil, the well may remain in the battery provided that the well is equipped with a separator and there is continuous measurement of the gas and liquid components or, alternatively, the measurement, accounting, and reporting procedures specified below are followed (see Figure 7.5).

Annual Gas Rate–WGR tests must be conducted on the well. An oil-gas ratio (OGR) must also be determined during this test. The WGR, estimated water production, water proration factor, and actual water production are determined in the same manner as indicated above (see Section 7.3.2).

Units: All gas volumes and GEV are to be in (10^3 m^3) and liquid volumes in (m^3).

1) Calculate well gas test rate (see Figure 7.6):

Well gas test rate = Well test gas volume (A) / Well test hours

2) Calculate estimated monthly well gas volume:

Estimated monthly well gas volume = Well gas test rate x Monthly total hours of well production

3) Calculate the OGR (see Figure 7.6):

OGR = Well test oil volume (B) / Well test gas volume (A)

4) Calculate actual well oil production:

Actual monthly well oil production = Estimated monthly well gas volume x OGR

5) Calculate actual total oil production:

Actual monthly total battery oil production = Sum of all actual monthly well oil volume

6) At the group measurement point, subtract the oil production volume (item 5) from the total liquid hydrocarbon volume to determine the total battery condensate production (the GEV of the total battery condensate volume, if not delivered for sale, must be added to

the measured group gas volume to determine the total battery gas volume) (see Figure 7.5):

Total battery condensate volume = Battery total liquid hydrocarbon volume (E) – Actual monthly total battery oil production

7) Calculate total estimated gas production for the battery:

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

8) Calculate proration factor for gas (see Figure 7.5):

   Gas Proration Factor (GPF) = (Total battery measured monthly gas volume [D] + GEV of total battery condensate volume [item 6]) / Total battery estimated monthly gas volume

9) Calculate actual monthly (prorated) well gas production:

   Actual monthly well gas production = Estimated monthly well gas volume x GPF

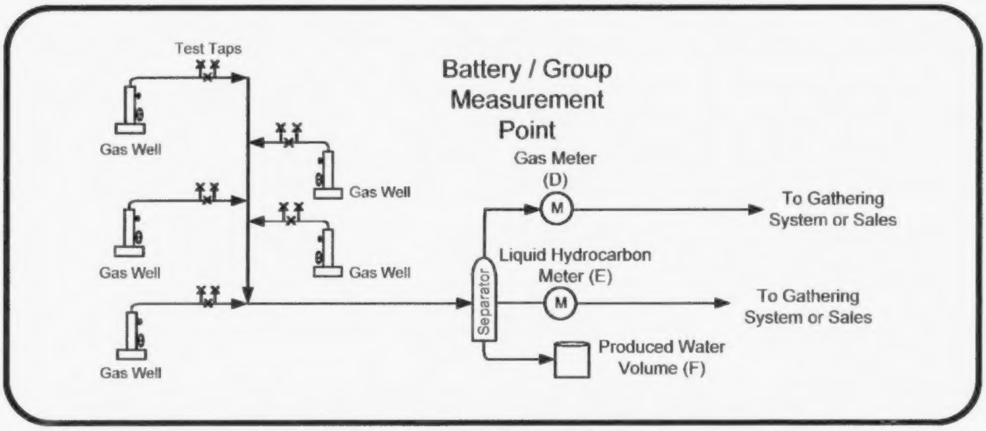

Test Taps
Battery / Group Measurement Point
Gas Well
Gas Well
Gas Well
Gas Well
Gas Well
Gas Meter (D)
M
To Gathering System or Sales
Liquid Hydrocarbon Meter (E)
M
To Gathering System or Sales
Separator
Produced Water Volume (F)

Figure 7.5. Typical gas multiwell proration outside SE Alberta battery

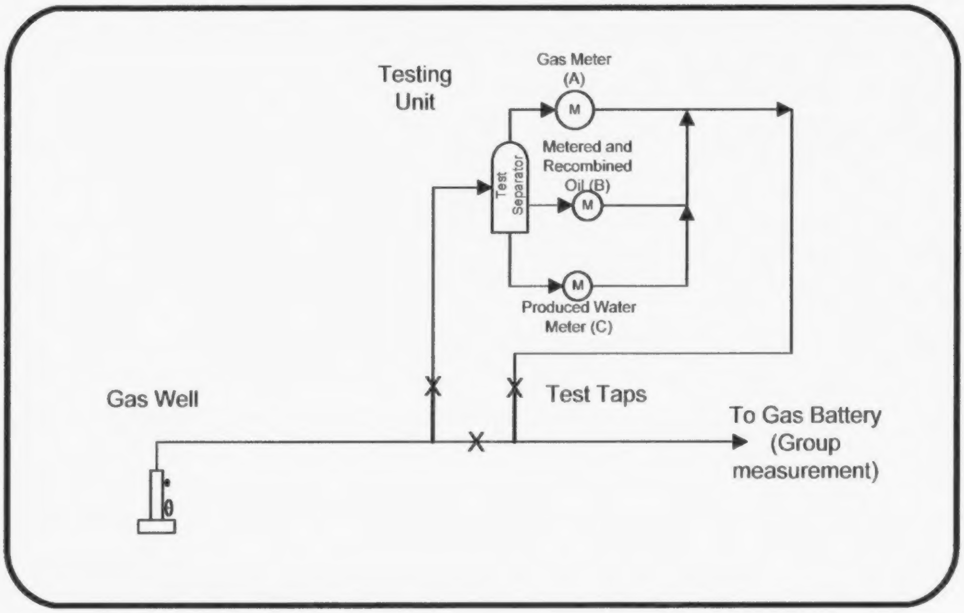

Testing Unit
Gas Meter (A)
M
Metered and Recombined Oil (B)
M
Test Separator
M
Produced Water Meter (C)
Gas Well
Test Taps
To Gas Battery (Group measurement)

Figure 7.6. Typical testing setup

Report the calculated monthly oil production volume as oil produced from the well. Prorate monthly condensate (if delivered for sale) and water production as in the normal proration battery in Section 7.3.2.

7.4 Gas Multiwell Effluent Proration Batteries

Gas wells in this type of battery have dedicated "effluent" or "wet gas" measurement, whereby total multiphase well fluid passes through a single meter (see Figure 7.7). This type of measurement must be subjected to testing regardless of the type of effluent meter used. For a new completion or recompletion of another zone in an existing well, effluent measurement is not allowed at a certain LGR level (see Section 7.4.1.1 for details).

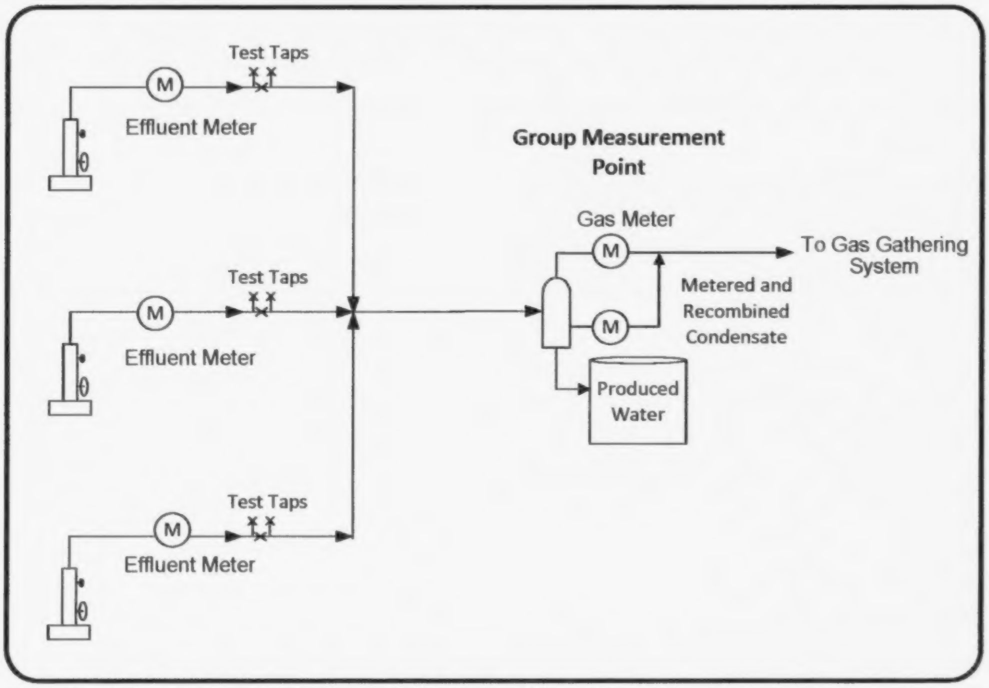

Test Taps
M
Effluent Meter
Test Taps
M
Effluent Meter
Test Taps
M
Effluent Meter
Group Measurement Point
Gas Meter
M
To Gas Gathering System
Metered and Recombined Condensate
M
Produced Water

Figure 7.7. Typical multiwell effluent proration battery configuration

Definitions

"Near measured" production	Gas well production that qualifies for effluent metering but requires annual or biennial testing based on the regulatory effluent-testing decision tree. Effluent correction factors are applied to the effluent-measured gas production. The effluent-corrected production volume is then multiplied by the well's water-gas ratio (WGR) to determine the estimated water production volumes.
"Deemed dry" production	Applies to gas effluent wells that qualify for testing exemption based on the effluent testing decision tree. Includes wells that are categorized within a zone-based effluent testing exemption where the average liquid gas ratio (LGR) results of testing are less than $0.056\ m^3/10^3\ m^3$.

"Measured" gas source	Production that is diverted through a separator and includes measurement of each phase (gas and liquid).

Production rates, WGR, CGR, and ECF determined during a well test must be used in the estimation/proration calculations within 60 days of the test until the next test is conducted.

Total battery gas production must be measured and prorated back to the individual wells, based on each well's estimated monthly gas production. Estimated well gas production is based on the total volume measured by the effluent meter multiplied by an ECF (see Figure 7.8). The uncertainty of measurement will increase with higher liquid rates, especially under liquid slugging conditions.

Figure 7.8 illustrates a typical gas well effluent measurement configuration. Production from the gas well passes through a line heater (optional), where it is heated. This is typically done to vaporize some of the hydrocarbon liquids and heat up the water and the gas in the stream before metering to prevent hydrate formation. For well testing purposes, test taps must be located downstream of this meter within the same pipe run. The line heater and/or the fuel gas tap, if present, must be upstream of the meter or downstream of the test taps to ensure that the test meter is subjected to the same condition as the effluent meter. After measurement, production from the well is commingled with other flow-lined effluent gas wells in the battery and sent to a group (battery) location, where single-phase (group) measurements of hydrocarbon liquids, gas, and water must be conducted downstream of separation.

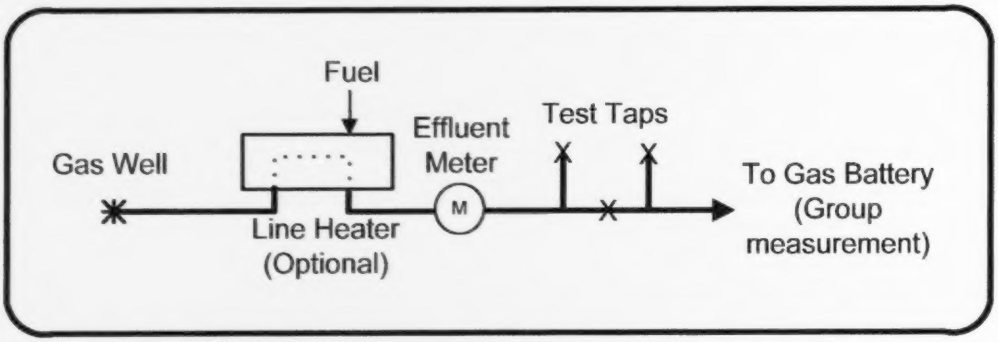


Figure 7.8. Typical gas well effluent metering configuration

For most wells, the required minimum well testing frequency is annual unless the criteria in Section 7.4.1.1 are met. Total battery water production must be measured and prorated back to the individual wells, based on each well's estimated monthly water production. Estimated well water production is based on a WGR, determined by periodic well tests multiplied by the estimated monthly well gas production.

Gas wells that are classified as producing oil, rather than condensate, must not be tied into an effluent proration battery, unless the well oil and gas production volumes are separated and measured prior to commingling with the effluent wells and either the "Exception" criteria in Section 5.5 are met or site-specific approval has been obtained from the ERCB prior to implementation.

If a gas well classified as producing condensate in a multiwell effluent proration battery is reclassified by the ERCB as producing oil, see Section 7.4.3.

7.4.1 Well Testing

Well testing is typically performed by directing well production downstream of the effluent meter and within the same pipe run through a three-phase portable test separator configured with dedicated meters for gas, condensate, and water (see Figure 7.9). Test equipment using two-phase separation is acceptable if hydrocarbon liquids are too small to be measured during typical well test durations. Other options that provide equivalent liquid volume determination accuracy may also be considered. For example, if a three-phase separator is not available, alternative equipment, such as a two-phase separator with a total liquid meter and continuous water cut analyzer, may be acceptable. The test must be conducted as follows:

- The test must begin only after a liquid level stabilization period within the test separator.
- The test duration must be a minimum of 12 hours.
- All new wells must be tested within the first 30 days of initial production.
- Consistent testing procedures must be used for consecutive tests to identify if a change in a well's flow characteristics has occurred.
- The gas, condensate, and water volumes must be measured.
- The condensate must be sampled during every test and subjected to a compositional analysis, which is to be used to determine the GEF. The sample may be taken from the condensate leg of a three-phase separator or the liquid leg of a two-phase separator (the water must be removed from the condensate before conducting the analysis).
- The GEF must be used to convert the liquid condensate volume determined during the test to a GEV, which will be added to the measured test gas volume to determine the total test gas volume if the condensate is not delivered for sale at the group measurement point. The ECF can then be determined based on whether the condensate is recombined with the gas (see Section 7.4.2).
- The WGR must be determined by dividing the test water volume by the sum of the measured test gas volume and the gas equivalent of the measured test condensate volume if the condensate is not delivered for sale at the group measurement point (see Section 7.4.2).
- For orifice meters, the effluent meter and the test gas meter must use 24-hour charts for a test period of 24 hours or less, unless electronic flow measurement (EFM) is used; for testing periods longer than 24 hours, 7-day charts may be used, provided that good, readable pen traces are maintained (see Section 4.3.4).

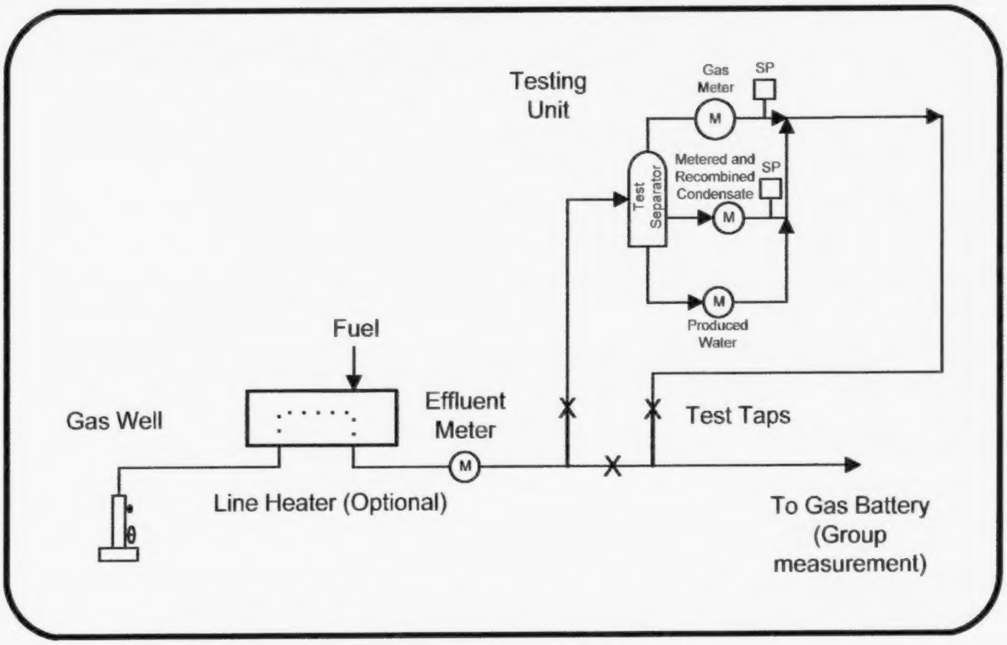

Testing
Unit
Gas
Meter
SP
M
Test
Separator
Metered and
Recombined
Condensate
SP
M
M
Produced
Water
Fuel
Gas Well
Effluent
Meter
M
Test Taps
Line Heater (Optional)
To Gas Battery
(Group
measurement)

Figure 7.9. Typical effluent well measurement configuration with test unit

7.4.1.1 Well Measurement and Testing Decision Tree

The type of measurement and testing frequency for wet measured wells must follow the decision tree process in Figure 7.10.

Note that the starting point for initial well completion or recompletion is different than for existing effluent measured zones/wells.

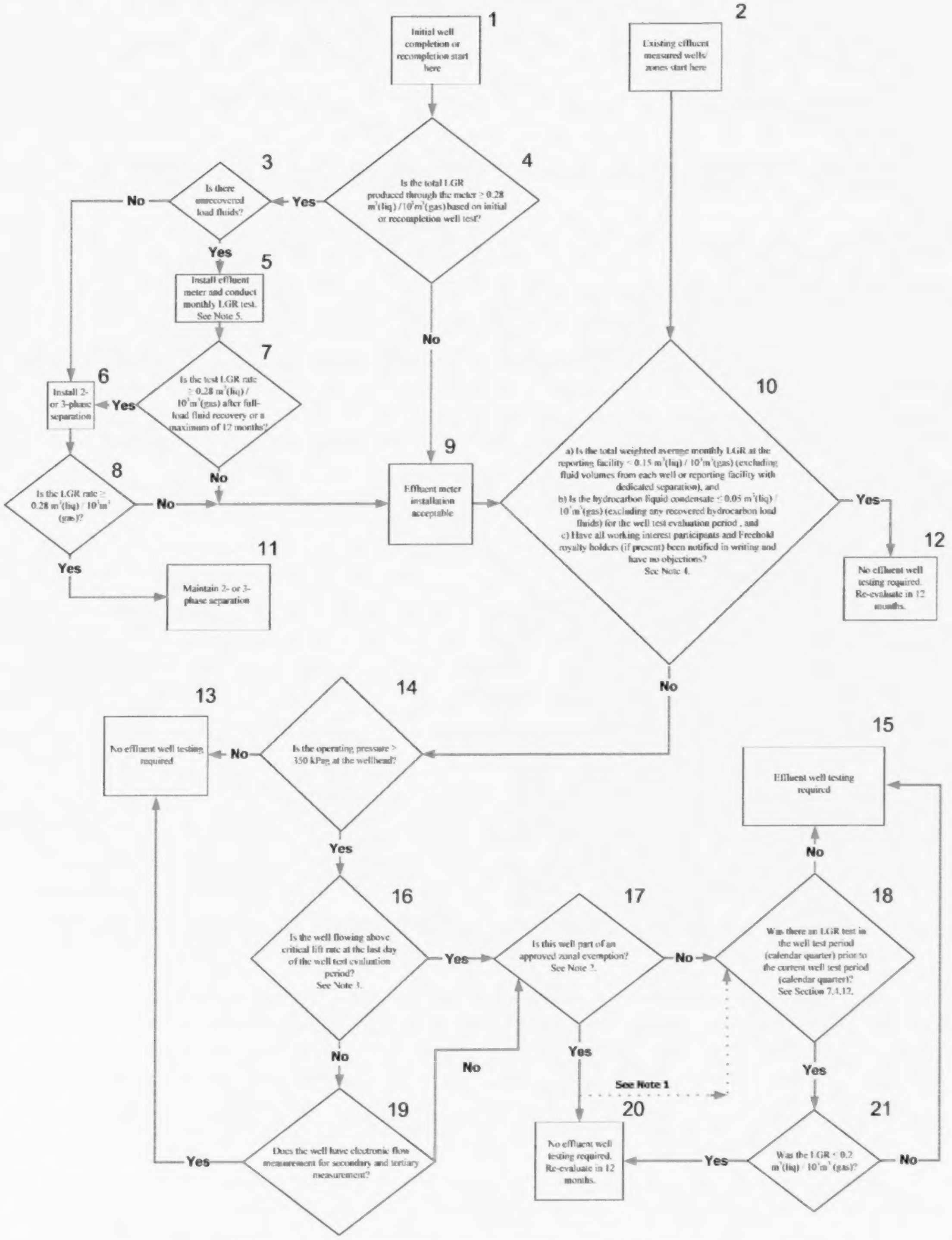

1
Initial well completion or recompletion start here
2
Existing effluent measured wells/ zones start here
3
Is there unrecovered load fluids?
4
Is the total LGR produced through the meter ≥ 0.28 m^3(liq) / 10^3m^3(gas) based on initial or recompletion well test?
Yes
No
Yes
5
Install effluent meter and conduct monthly LGR test. See Note 5.
6
Install 2- or 3-phase separation
7
Is the test LGR rate ≥ 0.28 m^3(liq) / 10^3m^3(gas) after full-load fluid recovery or a maximum of 12 months?
Yes
No
No
8
Is the LGR rate ≥ 0.28 m^3(liq) / 10^3m^3(gas)?
No
Yes
9
Effluent meter installation acceptable
10
a) Is the total weighted average monthly LGR at the reporting facility < 0.15 m^3(liq) / 10^3m^3(gas) (excluding fluid volumes from each well or reporting facility with dedicated separation), and
b) Is the hydrocarbon liquid condensate ≤ 0.05 m^3(liq) / 10^3m^3(gas) (excluding any recovered hydrocarbon load fluids) for the well test evaluation period , and
c) Have all working interest participants and Freehold royalty holders (if present) been notified in writing and have no objections?
See Note 4.
Yes
11
Maintain 2- or 3-phase separation
12
No effluent well testing required. Re-evaluate in 12 months.
No
13
No effluent well testing required
14
Is the operating pressure > 350 kPag at the wellhead?
No
Yes
15
Effluent well testing required
16
Is the well flowing above critical lift rate at the last day of the well test evaluation period? See Note 3.
Yes
17
Is this well part of an approved zonal exemption? See Note 2.
No
18
Was there an LGR test in the well test period (calendar quarter) prior to the current well test period (calendar quarter)? See Section 7.4.12.
No
No
Yes
No
Yes
See Note 1
Yes
19
Does the well have electronic flow measurement for secondary and tertiary measurement?
Yes
20
No effluent well testing required. Re-evaluate in 12 months.
21
Was the LGR < 0.2 m^3(liq) / 10^3m^3(gas)?
Yes
No

Figure 7.10. **Well measurement and testing decision tree.** (Text boxes are numbered from left to right.)

Note 1: Where all wells in a facility are above critical lift and in a deemed exempted zone, if the LGR is greater than 0.2 m^3 (liq)/10^3 m^3 (gas) at the respective facility inlet to which the wells flow, the zone is not exempted and the Note 1 path is to be followed.

Note 2: ERCB zonal measurement exemptions are by special approvals only.

Note 3: The Turner Correlation[1] is used to approximate critical lift. The calculation below produces a value in million standard cubic feet (mmscf) per day. Use a factor of 28.3168 10^3 m^3/mmscf to convert to metric units. Although there have been further refinements to the Turner Correlation calculation, the formulas below will be applied to determine critical lift as it relates to the well measurement and testing decision tree. These simplified formulas assume a fixed-gas gravity (G) of 0.6 and fixed-gas temperature (T) of 120°F.

$$v_g(Water) = \frac{5.62(67 - kP)^{0.25}}{(kP)^{0.50}}$$

$$v_g(Condensate) = \frac{4.02(45 - kP)^{0.25}}{(kP)^{0.50}}$$

$$k = \frac{2.693G}{ZT}$$

$$q_g = \frac{3.06Pv_gA}{ZT}$$

G = gas gravity
P = Pressure (absolute) - lb force / square inch
T = Temperature (absolute) – degrees Rankine
V_g = Minimum gas velocity required to lift liquids – ft / second
Z = Compressibility factor
A = Cross sectional area of flow – square feet
q_g = Flow rate – mmscf / day

The following represents a sample Turner Correlation calculation:

Evaluation period: November–October
SCADA daily average tubing pressure, October: 684.6 kPa
Turner Correlation formula: assumes G = 0.6
T = 48.9°C (120°F)
Z = 0.9

Variable	Value	Units	Calculation
G	0.6		
Z	0.9		
T	580	Rankin	[(48.9 x 1.8) + 32] + 460
k	0.003095		(2.693 x 0.6)/(0.9 x 580)
P	114	PSIA	(684.6 kPa / 6.89475) + (101.325 kPa / 6.89475)
A	0.0217	Ft^2	[3.1415 x (1.995 inches/12)^2]/4 (Tubing size = 2 3/8 inches)
q_g	0.392	mmscf/d	
q_g	11.10	10^3 m^3/d	0.392 mmscf x 28.3168 10^3 m^3 / mmscf

If both condensate and water are present, use the Turner Correlation for water to evaluate system behavior. The Turner Correlation uses the cross-sectional area of the flow path when calculating liquid lift rates. For example, if the flow path is through the tubing, the minimum gas rate to lift water and condensate is calculated using the inside diameter (ID) of the tubing. When the tubing depth is higher in the wellbore than the midpoint of perforations (MPP) in a vertical well, the Turner Correlation does not consider the rate required to lift liquids between the MPP and the end of the tubing. Ultimately, the liquid lift rate calculations are based on the tubing's ID or the area of the annulus and not on the casing's ID unless flow is up the casing only.

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[1] Turner, R. G., Hubbard, M. G., and Dukler, A. E., 1969, "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells," *JPT* 21(11): 1475–1482.

Note 4: Average Monthly LGR/CGR Calculation

Follow Figure 7.10 to determine if a facility exemption is appropriate for specific wells that flow to the reporting facility based on the total liquid/condensate volumes versus the total gas volume measured at the group measurement point for the reporting month. Production volumes include not only volumes measured at a group measurement point, but all fluid production volumes used for reporting purposes. This requires accounting for all fluid volumes that are received into or delivered out of the reporting facility for that reporting month.

LGR = [Total group measured liquids (condensate + water) + (Disposition + Inventory change before group measurement) – Liquid received] / [Total group measured gas + (fuel + flare + vent before group measurement) + Disposition before group gas measurement – Gas received]

CGR = [Total group measured condensate + (Disposition + Inventory change before group measurement) – Condensate received] / [Total group measured gas + (fuel + flare + vent before group measurement) + Disposition before group gas measurement – Gas received]

Note 5: An initial well test must be conducted within 30 days of production and monthly thereafter. The WGR, CGR, and ECF factors from the last test must be used to calculate estimated production until the next test is conducted. Once full fluid recovery is achieved or the 12-month period is passed, whichever comes first, the well must be evaluated according to the decision tree process based on the last well test.

7.4.1.2 Well Test Evaluation

The well testing evaluation period is based on a cycle of 12 consecutive months that all of the wells in a reporting facility will identically follow. The well test evaluation period must end two months before the planned calendar quarter in which the required well testing will be conducted for a reporting facility. Once the evaluation period is chosen, it will remain fixed for a reporting facility. Well testing, when required according to Figure 7.10, must occur once in the fixed calendar quarter. Figure 7.11 provides an illustrated example.

Well and reporting facility data are gathered for the 12-month period identified. The wells and/or the reporting facility would be analyzed within the context of the well measurement and testing decision tree. Initializing the design will establish the cycle that is repeated year over year. The operator is free to choose the well testing calendar quarter based on operations. The illustrated example below typically fits a well testing system in which winter road access is available.

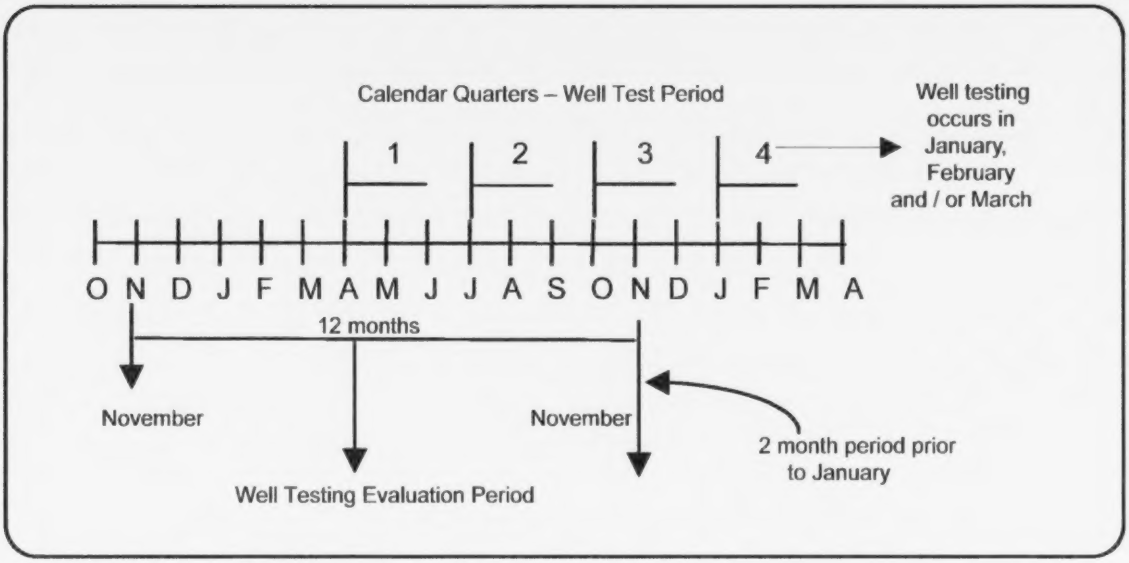
Calendar Quarters – Well Test Period
1
2
3
4
Well testing occurs in January, February and / or March
O N D J F M A M J J A S O N D J F M A
12 months
November
November
2 month period prior to January
Well Testing Evaluation Period

Figure 7.11. Well test evaluation example

For the purposes of evaluating text box 10 of the well measurement and testing decision tree in Figure 7.10, the reporting facility and the affected wells (i.e., wells without well separation) will be on the same well testing evaluation period. If, however, a reporting facility has operating characteristics such that a reporting facility well testing exemption (text box 10) is not possible, the well testing evaluation period can become unique to a well. This means that for a well that requires testing according to the well measurement and testing decision tree, the well maintains a fixed well testing evaluation period, but the well testing evaluation period may not be the same for all of the wells in a reporting facility. If a facility is of such a size that it would take more than one calendar quarter to test all of the wells, an operator can choose the calendar quarter in which a well test is to occur which in turn determines the Well Testing Evaluation Period. Once the well testing period (calendar quarter) is chosen, the operator must test once in the fixed calendar quarter period.

The pressure data, as recorded by the well site measurement equipment, will be the monthly average for the last month of the well test evaluation period. If no tubing or casing pressure records are continuously recorded, then the upstream static pressure data from the well's flow meter may be used to approximate the tubing or casing pressure provided that the well's flow meter is located on the same lease site as the wellhead.

7.4.1.3 Record Keeping

The following lists the minimum records required related to well testing and/or the well measurement and testing decision tree (where applicable):

General Information

1) Producer
2) Reporting facility – name and surface location
3) PRA reporting code
4) Well – name
5) Well – unique well identifier (UWI)
6) Production formation – name and/or zone code

Well Test Information

7) Current well testing date
8) Last well test date
9) Effluent well meter run – internal diameter (mm)
10) Meter run orifice size (mm) (if applicable)
11) Test tap location (relative to effluent meter)
12) Test tap connection – diameter (mm)
13) Last gas sample date
14) Last condensate sample date
15) Test gas average rate (10^3 m^3/day)
16) Test condensate average rate (m^3/day)
17) Test water average rate (m^3/day)
18) Current WGR ($m^3/10^3$ m^3)
19) Current CGR ($m^3/10^3$ m^3)
20) Current LGR ($m^3/10^3$ m^3)
21) Last WGR ($m^3/10^3$ m^3)
22) Last CGR ($m^3/10^3$ m^3)
23) Last LGR ($m^3/10^3$ m^3)
24) ECF – last value calculated
25) ECF – current value calculated

Decision Tree Information

26) Wellhead tubing internal diameter (mm)
27) Wellhead casing internal diameter (mm)
28) Wellhead tubing pressure (KPa)
29) Wellhead casing pressure (KPa)
30) Effluent meter monthly average D/P for evaluation period (kPa) – listed by month (optional)
31) Effluent meter monthly average static pressure for evaluation period (KPa) – listed by month
32) Effluent meter monthly average temperature for evaluation period (°C) – listed by month (optional)
33) Evaluation period average reporting facility LGR
34) Evaluation period average reporting facility CGR
35) Artificial lift method (i.e., cycling, plunger control)
36) Well chart or EFM – model and make
37) Well test evaluation period starting month
38) Well test evaluation period ending month
39) Date well dropped below critical velocity
40) Critical lift calculation for evaluation period
41) Well load fluid volumes for evaluation period
42) Meters used in facility LGR calculations
    a) Meter tag

    - b) Meter location
    - c) Meter volume
    - d) Meter units (10^3 m^3, etc.)

43) Well flow volume prior to recompletion (optional)

44) Well recompletion flow volume (optional)

7.4.1.4 Revocation of Exemption

Below are the criteria under which a testing exemption for an effluent gas well may be revoked. Baseline well testing must be conducted if a testing exemption is revoked for any of the following reasons:

1) Noncompliance. Potential areas of noncompliance include
    - a) incorrect exemption calculations,
    - b) inadequate record keeping,
    - c) source data for exemption calculations cannot be validated, and
    - d) incorrect application/implementation of the well measurement and testing decision tree.

2) A working interest participant or Freehold royalty holder for any flowing well to the reporting facility objects to the exemption.

Additionally, if the ERCB has a concern with the activities, operations, production data, or reporting associated with well testing, on notice in writing, the ERCB can partially or fully revoke well testing exemptions and impose, modify, or substitute well testing conditions for any period of time. The ERCB will advise the operator in writing as to the reason for the revocation, provide a reasonable time period for the operator to meet the conditions set by the ERCB, and provide an opportunity for the operator to comment.

7.4.2 Production Volume Calculations

Monthly production volumes are to be calculated as follows (see Figure 7.12).

Units: All gas volumes and GEV are to be in 10^3 m^3 and liquid volumes in m^3.

Testing-exempted battery

For a battery that is exempt from testing, the volumetric calculation is to be based on the following:

ECF = 1.00000

WGR = Battery-based water-gas ratio

LGR = Battery-based liquid-gas ratio

CGR = Battery-based condensate-gas ratio

If battery condensate volumes are recombined back into the gas stream, the gas equivalent of the recombined liquids will be calculated and added to the measured group gas volume to obtain the total battery gas volume. Condensate liquid volumes will not be prorated to the wells.

If battery condensate volumes are tanked and trucked out for sale, the condensate liquid volumes will be prorated back to the wells in the battery based on the calculated battery CGR.

Testing-exempted wells

For a battering with both exempted and nonexempted wells, the volumetric calculation is to be based on the following:

ECF = 1.00000 for exempted wells

For the wells that require testing, water production will be prorated to each well based on the well's individual WGR (derived from the well tests) multiplied by its estimated gas production. For those wells that are test exempt, a battery WGR will be established and applied to all the test-exempt wells after netting off the estimated water production of the tested wells.

If battery condensate volumes are recombined back into the gas stream, the gas equivalent of the recombined liquids will be calculated and added to the measured group gas volume (recombined volume and recombined analysis). Condensate liquid volumes will not be prorated to the wells.

If battery condensate volumes are tanked and trucked out for sale, the tested wells' estimated condensate production will be calculated based on each well's CGR (derived from the well tests) multiplied by the well's estimated gas production. For those wells that are test exempt, a battery CGR will be established and applied to all the test-exempt wells after netting off the estimated condensate production of the tested wells.

Nonexempted wells

If there are no exempted wells in the battery and condensate is delivered for sale at the group measurement point, go directly to item 8. Otherwise, follow items 1 to 7.

1) **Calculate the ECF:**

   ECF = (Well test gas volume [B] + GEV of well test condensate [C]) /
   Effluent gas volume measured during test (A)

2) **Calculate estimated gas production for each well:**

   Estimated monthly well gas volume = Monthly well effluent volume x ECF

3) **Calculate the WGR:**

   WGR = Well test water volume (D) / (Well test gas volume [B] + GEV of well test condensate [C])

4) **Calculate estimated water production for each well:**

   Estimated monthly well water volume = Estimated monthly well gas volume x WGR

5) **Calculate total battery estimated volumes (gas and water):**

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

   Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

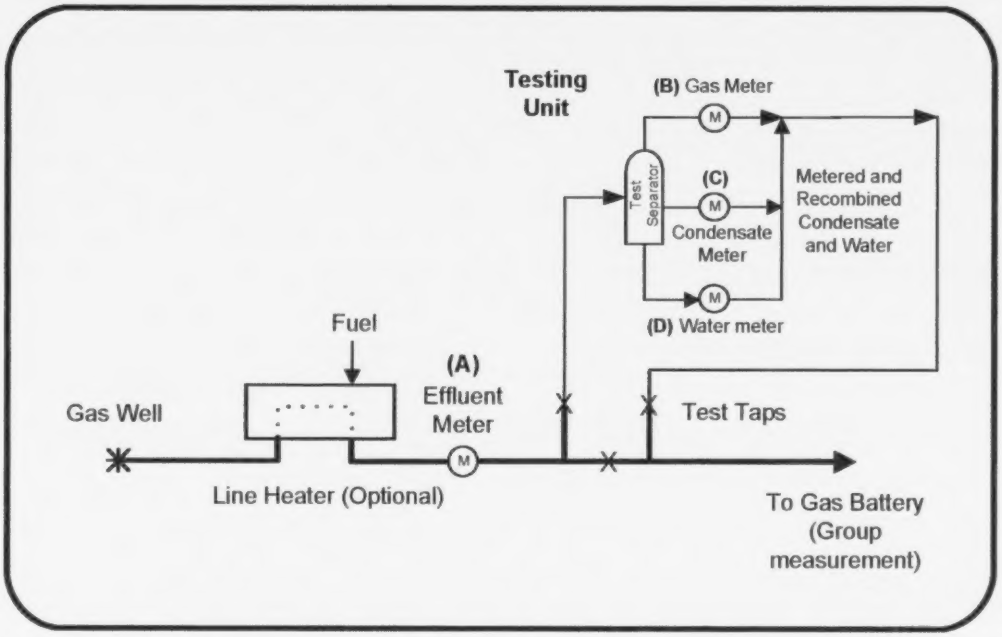
Testing Unit
(B) Gas Meter
M
Test Separator
(C)
M
Condensate Meter
Metered and Recombined Condensate and Water
M
(D) Water meter
Fuel
(A) Effluent Meter
Gas Well
M
Test Taps
Line Heater (Optional)
To Gas Battery (Group measurement)

Figure 7.12. Effluent well meter testing configuration with condensate production

6) **Calculate proration factors for gas and water:**

GPF = (Total battery measured monthly gas volume + GEV of total battery condensate) / Total battery estimated monthly gas volume

WPF = Total battery actual monthly water volume / Total battery estimated monthly water volume

7) **Calculate actual monthly (prorated) well production:**

Actual monthly well gas production = Estimated monthly well gas volume x GPF

Actual monthly well water production = Estimated monthly well water volume x WPF

For the battery with condensate delivered for sale at the group measurement point:

8) Calculate the ECF:

ECF = Well test gas volume (B) / Effluent gas volume measured during test (A)

9) Calculate the well CGR:

CGR = Well test condensate volume (C) / Well test gas volume (B)

10) Calculate the WGR:

WGR = Well test water volume (D) / Well test gas volume (B)

11) Calculate estimated gas, condensate, and water production for each well:

Estimated monthly well gas volume = Monthly well effluent volume x ECF

Estimated monthly well condensate volume = Estimated monthly well gas volume x CGR

Estimated monthly well water volume = Estimated monthly well gas volume x WGR

12) Calculate total estimated gas, condensate, and water production for the battery:

Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

Total battery estimated monthly condensate volume = Sum of all estimated monthly well condensate volumes

Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

13) Calculate total battery monthly gas, condensate, and water production:

Total battery monthly gas volume = Total gas disposition + Flare + Vent + Fuel (take off before sales meter)

Total battery monthly condensate volume = Total condensate disposition + inventory change

Total battery monthly water volume = Total water disposition + inventory change

14) Calculate proration factors for gas, condensate, and water:

Gas Proration Factor (GPF) = Total battery monthly gas volume / Total battery estimated monthly gas volume

Condensate Proration Factor (CPF) = Total battery monthly condensate volume / Total battery estimated monthly condensate volume

Water Proration Factor (WPF) = Total battery monthly water volume / Total battery estimated monthly water volume

15) Calculate actual monthly (prorated) well production:

Actual monthly well gas production = Estimated monthly well gas volume x GPF

Actual monthly well condensate production = Estimated monthly well condensate volume x CPF

Actual monthly well water production = Estimated monthly well water volume x WPF

7.4.3 Exception

If an existing gas well classified as producing condensate in a multiwell effluent proration battery is reclassified by the ERCB as a gas well producing oil, the well may remain in the multiwell effluent proration battery provided that the well is equipped with a separator and there is continuous measurement of the gas and liquid components or, alternatively, the effluent meter is left in place and the measurement, accounting, and reporting procedures specified below are followed (see Figure 7.13).

Annual ECF-WGR tests must be conducted on the well. (These types of wells do not qualify for the test frequency exemptions or reductions described above.) An OGR, to be used for the well oil production calculation, must also be determined during this test. The WGR, estimated water production, water proration factor, and actual water production are determined in the same manner as indicated above.

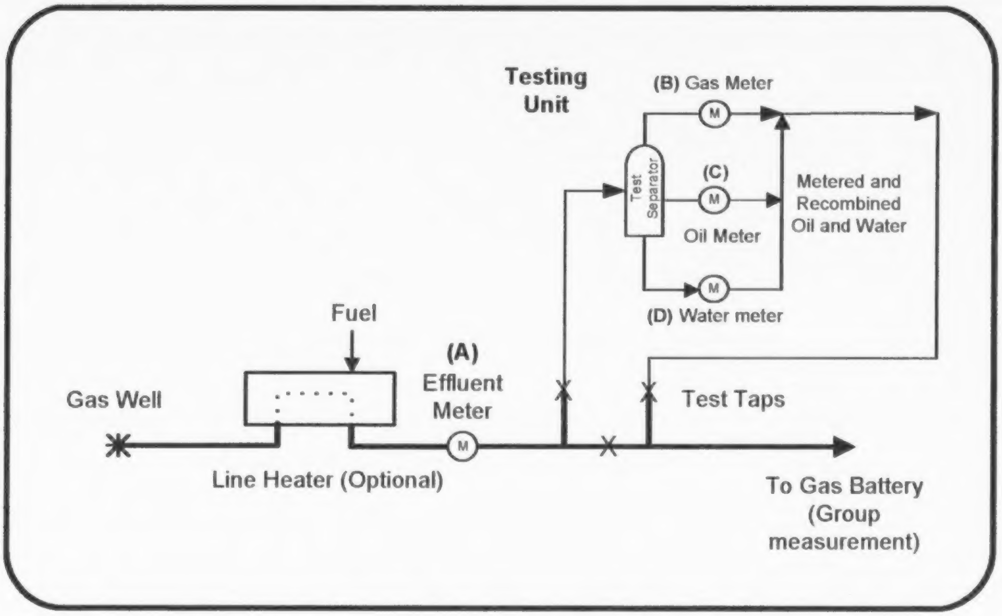
Testing Unit
(B) Gas Meter
M
Test Separator
(C)
M
Oil Meter
Metered and Recombined Oil and Water
M
(D) Water meter
Fuel
(A) Effluent Meter
M
Gas Well
Test Taps
Line Heater (Optional)
To Gas Battery (Group measurement)

Figure 7.13. Effluent well meter testing configuration with oil production

1) Calculate the ECF:

   ECF = Well test gas volume (B) / Effluent gas volume measured during test (A)

2) Calculate estimated gas production for the well:

   Estimated monthly well gas volume = Monthly well effluent volume x ECF

3) Calculate the OGR:

   OGR = Well test oil volume (C) / Well test gas volume (B)

4) Calculate actual well oil production:

   Actual monthly well oil volume = Estimated monthly well gas production x OGR

5) Calculate the total monthly battery condensate volume:

   Total battery condensate volume = Total battery liquid hydrocarbon volume –
   Total monthly oil volume

6) Report the calculated monthly oil production volume as oil produced from the well. Prorate monthly gas and water production as in Section 7.4.2.

8 Gas and Liquid Sampling and Analysis

This section outlines the gas and related liquid sampling and analysis requirements for the various categories of production measurement. These requirements add to the requirements in Sections 11.070 and 11.080 of the *OGCR*, which continue to apply. The requirements vary, depending on a number of factors, such as production rate, potential for the composition to change over time, and the end use of the fluid. Where appropriate, conditions have been identified under which the sampling and analysis requirements may be altered or eliminated altogether. The ERCB will also consider applications for further requirement alterations or eliminations if the licensee can demonstrate that measurement accuracy would either not be reduced or not impact royalty, equity, or reservoir engineering concerns.

8.1 General

Gas and liquid analyses are required for the determination of gas volumes, conversion of liquid volumes to gas equivalent, and product allocation. The sampling and analysis requirements identified in this section pertain only to those areas that affect the calculations and reporting required by the ERCB.

These requirements apply solely to the measurement of hydrocarbon fluids and are not intended to supersede the business requirements that licensees are required to meet regarding product allocations.

If oil is produced from gas wells (as defined by the ERCB), it must be reported as liquid oil production and not as a gas equivalent volume (GEV), so compositional analysis of the oil is not required for that purpose. The oil produced could be combined with the gas and delivered to a gas plant or other facilities for further processing, or the oil could be separated from the gas at the well equipment and directed to tankage, and then on to sales or further treatment.

Gas density and composition are integral components of gas volume calculations and plant product allocation calculations. For differential producing meters, such as orifice meters, venturi meters, and flow nozzles, the accuracy of a computed volume and component allocations are very sensitive to the accuracy of the compositional analysis, which is the basis for compressibility factors and density determination. For linear meters, such as ultrasonic and vortex, the compositional analysis is primarily used to determine the compressibility factors.

If liquid condensate produced from gas wells is either recombined with the gas well production or trucked to the inlet of a gas plant for further processing, the compositional analysis from a condensate sample must be used to determine the GEV of the condensate, which must be added to the well gas volume for reporting purposes. A similar procedure applies to gas gathering systems where liquid condensate is delivered to other facilities for further processing and to gas plant inlets. For this reason, the condensate sampling requirements must mirror the gas sampling requirements.

If liquid condensate is separated at a well, battery, or gas gathering system and delivered from that point for sale or other disposition without further processing, the condensate must be reported as a liquid volume. Therefore, a compositional analysis of the condensate is not required for gas equivalent volume determination purposes but may be required for the purposes of the sale.

Sampling and analysis frequencies and updating requirements for the various production types are summarized in Section 8.4. Further details are provided in the sections that follow. These sampling frequencies are the base requirements for gas and related liquid measurement.

Sampling and analysis of oil/emulsion streams at oil and gas wells and batteries are performed to determine the relative oil and water content of the streams. Oil/emulsion sampling and analysis are discussed in Section 6.4.

8.2 Sampling Requirements

Except where noted in this directive, the gas sampling equipment and methodology must follow the requirements set out in API MPMS 14.1 (June 2001), Gas Processors Association (GPA) 2166-05, or other equivalent industry standards.

Except where noted in this directive, the condensate sampling equipment and methodology must follow the requirements set out in GPA 2174-93, the evacuated cylinder method cited in GPA 2166-05, or in other equivalent industry standards.

Samples and analysis may be obtained by any of the following methods:

- on-site gas chromatograph (GC)
- proportional sampling
- spot or "grab" sampling

Spot or grab samples are acceptable for obtaining gas and liquid analyses once per test or per determination, provided that uncertainty requirements in Section 1 are fulfilled. When the uncertainty requirements cannot be met, licensees must consider more frequent sampling, calculated analyses (see Section 8.3.1), proportional samplers, or chromatographs.

For example: If the analysis from one time period to the next is such that the density and/or compressibility changes cause the volume to change by more than the allowable uncertainty, a more frequent analysis is required or an alternative method of obtaining the sampled must be used.

The gas and liquid analyses must be updated when operating conditions are significantly altered (e.g., addition/removal of compression or line-heating, addition/removal of production sources in a common stream, wellbore recompletion).

If the gas volumes for all meters in the common stream (e.g., sales, fuel, flare, and injection gases) meet the uncertainty guidelines in Section 1, the licensee may use a single gas analysis for all meters on the common stream.

Sampling Procedures

1) Sample points must be located to provide representative samples.
2) Sample probes must not be located within the minimum upstream straight lengths of the meter.
3) Access from grade or platform must be provided for the sample point.
4) If sample transfer tubing is to be used, its length must be minimized.

5) The sample transfer tubing must be oriented to minimize the potential to trap liquids in gas samples and water in condensate samples.

6) A means must be provided to safely purge sample transfer tubing between the sample point and the connection point of the sample cylinder.

7) Sample containers must be clean and meet the pressure, temperature, and materials requirements of the intended service and have the required regulatory approvals as necessary.

8) The procedures used for sampling, transportation, handling, storage, and analysis must ensure that atmospheric contamination does not occur.

All samples must be analyzed using a gas chromatograph or equivalent to determine the components to a minimum of C7+ composition except for sales or delivery points where C6+ composition is acceptable if agreed upon by affected parties. The gas composition analysis must be determined to a minimum of four decimal points (as a fraction of 1.0000) or two decimal points (as a percentage of 100), and the relative density must be determined to a minimum of three decimal points.

8.2.1 Sample Point and Probes

The sample point location and probe installation requirements that follow apply to all ERCB measurement points.

With the exception of sales/delivery (royalty trigger) point measurement, current sample probe locations and installations existing prior to December 5, 2007, do not have to be upgraded to meet the following requirements. A sample probe must be installed according to the requirements below when an installation is relocated or reused for another well or facility.

Requirements for Gas Sampling

1) For sampling applications where the gas is at or near its hydrocarbon dew point, a sample probe must be used (e.g., any separator application where hydrocarbon liquids are present).

2) For gas applications where the gas is not near its hydrocarbon dew point, a sample probe is recommended.

3) The preferred location for gas sample points is the top of horizontal lines.

4) An optional location for gas sample probes is the side of vertical lines with the probe tip sloping 45° downward.

5) Sample probes should be located at least 5 pipe diameters downstream of any piping disturbances, such as bends, elbows, headers, and tees.

6) The location of the sample point must be such that phase changes due to changes in pressure and/or temperature are minimized. Specifically, for gases at or near their hydrocarbon dew point, sample points must not be located downstream of pressure-reducing components, such as control valves, flow conditioners, and regulators, or long lengths of un-insulated piping or within 5 pipe diameter downstream of an orifice plate.

7) Sample points may be located downstream of ultrasonic meters that experience minimum pressure drop through the meter unless a flow conditioner is used and the gas is at or near its hydrocarbon dew point, in which case the sample point must be upstream of the flow conditioner.

8) Insulation and heat tracing must be used to eliminate any cold "spots" between the sample point and the entry point into the sample container or gas chromatograph where the sample transfer tubing temperature falls below the hydrocarbon dew point, such as at all separator applications.

9) Sample points used to sample blends of two gas streams should have provision for mixing (e.g., upstream static mixer), with due consideration to potential phase changes brought about by a pressure drop associated with the mixing device.

10) Orifice meter impulse lines or transmitter manifolds lines must not be used for taking samples.

11) Level gauge connections must not be used for taking samples.

Requirements for Condensate Sampling

1) With the exception of two-phase separators, a sample probe is recommended.

2) A sample probe must be installed for samples to be used to determine water cut when there is emulsion or a mix of water and hydrocarbon, such as two-phase separators. For such applications, the sampling system design must meet the requirements of API MPMS 8.2 with respect to the use of mixers, sample probe location, and design.

3) The preferred location for condensate sample points is the side of horizontal lines.

4) An optional location for liquid sample points is the side of vertical lines with the probe tip sloping 45° downward.

5) The location of the sample point must be such that phase changes due to changes in pressure and/or temperature are minimized. Specifically, sample points must not be located where vapour breakout is likely (e.g., downstream of pressure-reducing components, such as orifice plates, flow conditioners, turbine, PD or Coriolis mass meters, control valves, and regulators or where the stream temperature has increased).

6) For separator applications, the sample point should be between the separator outlet and the flow/level control valve upstream of the meter, unless a pressure booster pump is used, in which case the sample point is between the pump discharge and the meter.

7) Orifice meter impulse lines or transmitter manifolds lines must not be used for taking samples.

8) Level gauge connections must not be used for taking samples.

8.2.2 H_2S Sampling and Analysis

This section is applicable to obtaining high pressure samples. Special considerations, such as extra sample(s) or purging, should be taken when obtaining low pressure samples (e.g., Boot, treater, stabilizer, acid gas).

Hydrogen sulphide (H_2S) is a reactive molecule, which presents challenges for sampling and analysis of gas mixtures containing it. Typically H_2S is lost during sampling (and analysis), resulting in underreporting of H_2S concentrations. Factors that affect representative sampling and analysis accuracy (i.e., the amount of H_2S lost) are

1) presence of air, water, or other sulphur-containing molecules;
2) presence of reactive or absorptive sampling container surfaces;
3) presence of a liquid phase, which can absorb H_2S;
4) H_2S concentration;
5) sample pressure and temperature;
6) analysis method; and
7) time lapse between sampling and analysis.

The amount of H_2S lost can be reduced by

- proper sample point selection, which minimizes the presence of contaminants such as air, water, and amines;
- using clean containers made of materials that minimize H_2S reactions or absorption; and
- minimizing the time between sampling and analysis.

Typical materials of construction for cylinders are stainless steel and aluminum. Inert coated cylinders, glass containers, and non-absorptive elastomer bags can be considered to further minimize H_2S degradation, especially for concentrations of H_2S less than 5000 ppm when moisture is present.

The choice of analytical technique also affects the amount of H_2S reported. Instrumental techniques, such as gas chromatography, are typically more precise than chemistry techniques, such as Tutweiler titrations or stain tubes. However, such instrumental techniques are often impractical for well site applications.

Therefore, consideration should be given to method limitations and sample degradation as they relate to the specific reporting requirements in determining the best approach.

See Table 8.1 for analysis technique comparison.

With the exception of ppm level concentrations of H_2S in the presence of moisture, a field H_2S determination and a laboratory GC analysis are recommended. These provide a degree of redundancy and a check of the field analysis. Above 5 per cent H_2S, the GC value is typically more reliable. Below 5 per cent H_2S, the higher of the two values should be used. Unexpectedly large variances between lab and field H_2S values need to be investigated.

Table 8.1. H_2S analysis technique comparison

Method	Lower detection limit	Advantages	Limitations
On-line GC	500 ppm	Real time, accuracy Minimal time lapse	Capital cost, ongoing maintenance
Lab GC	500 ppm	Precision, accuracy	Potential degradation during transport (varies with H_2S concentration)
Tutweiler (GPA C-1)	1500 ppm	On site	Titration apparatus, reagent quality, variability in operator technique, including visual endpoint detection, computations, mercaptan interference
Stain Tubes (GPA 2377)	1 ppm	On site	Poor precision (± 25%) Matrix effects, (see manufacturer's specifications)

Analysis by gas chromatography is the preferred method at higher H_2S concentrations.

For H_2S concentrations between 1500 and 5000 ppm, it is recommended that both stain tube and Tutweiler values be obtained if on-line GC is not used.

If high accuracy of low-level (below 1500 ppm) H_2S concentration is required, consideration should be given to using a low-level sulphur-specific detector, such as a GC sulphur chemiluminescence detector. The use of containers that minimize degradation and the time lapse between sampling and analysis is also recommended in these situations.

Refer to Appendix 5 for more detail on the analytical methods used in the industry for determining H_2S concentrations in gas samples.

8.2.3 Compositional Analysis of Natural Gas

The two recommended procedures for compositional analysis of natural gas are based on GPA Standard 2286-95: *Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography* and GPA Standard 2261-00: *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*.

If a thorough description of the C7+ fraction (molecular weight and density) is required, analytical methods based on GPA Standard 2286 are more accurate and preferred. Specifically, GPA Standard 2286 makes use of a high-resolution column and flame ionization detector to separate and quantify the heavier components (C7+), which is then used for calculation purposes. Extended analysis of natural gases is common but has not been fully standardized; therefore some inter-laboratory bias may occur.

If the C7+ properties are well defined or have been agreed upon by all affected parties, analytical methods based on GPA Standard 2261 are suitable. The principal advantage of the precut method specified in GPA Standard 2261 is that all of the C7+ components can be grouped together into a single sharp chromatograph peak. Grouping of the numerous heavy compounds results in more precise measurement of the combined peak area. The primary disadvantage of GPA Standard 2261 is the lack of information gained with respect to the composition of the C7+ fraction. Inherently, if the composition of the C7+ fraction is unknown, some agreed-upon physical properties must be applied for calculation purposes.

The GC C7+ calibration is also affected, which increases the uncertainty of the C7+ measurement and heating value computation.

If detailed information on C7+ physical properties is not available, default values can be applied, as in Table 8.2.

Table 8.2. Recommended default values for C7+ properties*

Component	Molecular mass (grams per mole)	Liquid density (kg/m³ at 15°C)	Heating value (MJ/m³)
C7+, Heptanes plus	95.00	735.0	195

* C7+ is a pseudo-compound. The values have in most cases had been found to adequately represent the heavier fraction of natural gas samples.

8.3 Gas Equivalent Factor Determination from Condensate

GEF is the volume of gas (10^3 m^3 at standard conditions) that would result from converting 1.0 m^3 of liquid into a gas.

GEF is used when there is a requirement to report the gas equivalent volume (GEV) of condensate and other hydrocarbon liquids to the ERCB.

The GEF of a liquid may be calculated by any one of three methods (see Appendix 6), depending upon the type of component analysis conducted on the liquid (by volume, mole, or mass fractions) and the known properties of the liquid.

Engineering Data

Specific constants are used in calculating the GEF. Absolute density of liquids should be used instead of relative density.

The examples in Appendix 6 present the different methodologies used to calculate the GEF. All physical properties are based on GPA Standard 2145-03 (2003 or later) published data.

1 kmol = 23.645 m^3 @ 101.325 kPa and 15°C

8.3.1 Calculated Compositional Analyses

In some instances, representative sampling of a hydrocarbon stream is not possible or feasible because of economics, and calculation of a fluid composition is required, as described below:

Calculated Well Stream Analysis: It is not possible to accurately sample multiphase streams, so the composition of a recombined well stream must be determined by calculation. Such an analysis is typically not used for measurement, as it represents a multiphase fluid stream and most gas is measured as single phase. However, some companies use this analysis for calculation of gas volumes from wet- (multiphase) measured wells. Calculated well stream analyses are most commonly used in product allocation calculations.

Calculated Group Analysis: It is often difficult to accurately determine the average composition of fluids at a commingled group measurement point, as wells/sources to the group system flow at different rates and the composition is constantly changing. The recommended options for sampling these streams are on-line gas chromatographs or proportional sampling systems. However, if the recommended options are not practical or economical, a flow-weighted calculated analysis may be a viable option.

Calculated Single Analysis: Sometimes a single analysis cannot represent the composition for an entire measurement period. In such cases, multiple analyses of a single point must be combined to determine the composition for the period. An example of this is a sales gas stream where a proportional sample is taken weekly but a single composition for the month is required.

The principles to be followed for each of these calculated analyses follow.

8.3.1.1 Calculated Well Stream Compositional Analysis

This type of analysis applies to wells only and is meant to represent the hydrocarbon fluid composition produced from a well and/or delivered to a gathering system. In most cases, it represents the composition of hydrocarbons being produced from the reservoir. The calculation is a flow-weighted recombination of the hydrocarbon gas and liquid streams. The accuracy of the flow rates used in this calculation is as important as the gas and liquid composition. The gas and liquid flow rates used should be from the same day that the gas and liquid samples were obtained. Use of flow rates from a different period of time than the sample date can result in significant errors because both flow rates and composition will change with changes in process conditions (primarily temperature and pressure); applying flow rates from different periods does not recognize these changes.

Flow rates from the day of sampling should be used in determining recombined compositions, with the following exceptions:

- When the daily liquid-to-gas ratio is constant, volumes from an extended period (i.e., multiday, up to monthly) may be used.
- If some of the liquid stream is not recombined in a month (i.e., it dropped to tank), the composition (flow volume) of the liquids not recombined must be deducted from the initial recombined composition. This is typically done by recalculating the recombined composition with new flow rates, typically the flow rates for the month.

See the example in Appendix 7.

8.3.1.2 Calculated Group Compositional Analysis

This type of analysis is a flow-weighted representation of the hydrocarbon fluid composition produced from a group of wells or meter points. It is often used at commingled group points (inlets, compressors, certain process points) where it is difficult to obtain representative samples using spot sampling techniques. Ideally, proportional samplers should be employed in such situations. However, when proportional sampling is not practical or possible, a calculated group analysis can be determined based on the volume and composition of the wells/meters that flow to the commingled point. The accuracy of the flow rates used in this calculation is as important as the gas and liquid composition. The flow volumes used for each well/meter should be "actual" measured volumes for the period that the analysis is being calculated for, typically monthly.

For example, five gas wells producing from different pools with different composition deliver gas to a compressor station where the gas is measured. Accurate spot sampling at the compressor station is difficult due to changing flow rates at the wells. Using spot samples taken at the wells and monthly flow rates, the producer calculates a group analysis for the compressor station meter. Care must be taken when separator liquids are produced that all hydrocarbons are correctly accounted for, regardless of the phase.

See the example in Appendix 7.

8.3.1.3 Calculated Single Compositional Analysis

This type of analysis is a flow-weighted representation of the hydrocarbon fluid composition determined at a single sample point. It is typically used at sample points that have variable compositions and are sampled frequently (e.g., weekly) using spot or proportional sampling. Ideally, proportional samplers or gas chromatographs should be employed in such situations. However, when proportional sampling is not practical or possible, a calculated single analysis can be determined based on the volume and composition of a group of analyses at the sample point. The accuracy of the flow rates used in this calculation is as important as the gas and liquid composition. The flow volumes used for each sample should be "actual" measured volumes for the period that the analysis is representative of. For example, a producer takes spot samples of an inlet stream weekly because proportional sampling or on-line sampling is not practical. Using weekly flow rates, the producer calculates a monthly flow-weighted composition of the inlet stream.

See the example in Appendix 7.

8.4 Sampling and Analysis Frequency

Table 8.3 gives the analysis update frequency for gas and condensate streams. The sampling and analysis of condensate (if applicable) must be done at the same time as the gas sampling. The configurations shown in Figures 8.1 through 8.17 are examples. In each case, other similar configurations may also apply. Sampling frequencies are defined as follows:

Initial *– an analysis is required within the first six months of operation only, with no subsequent updates required.*

Monthly *– an analysis is required at least once per calendar month.*

Quarterly *– an analysis is required at least once per calendar quarter.*

Semiannually *– an analysis is required at least once every two calendar quarters.*

Annually *– an analysis is required at least once every four calendar quarters.*

Biennially *– an analysis is required at least once every eight calendar quarters.*

Calendar quarters *are January to March, April to June, July to September, and October to December.*

For example, for a biennial frequency, if the last sample was taken in July 2006, the operator has to take another sample by the end of September 2008 (end of the calendar quarter).

New gas and liquid samples must be taken for all new wells and measurement points by the end of the month following the first month of production. For the time period prior to receipt of a new composition, a substitute composition may be used for gas measurement and gas equivalent of liquid calculations. For wells, substitute compositions should be from a well producing from the same pool with similar separator operating conditions or from samples taken during well testing. Compositions taken during well tests should be carefully reviewed prior to use, as samples are typically taken at different conditions from those the well produces at and there are often contaminants in test samples (e.g., nitrogen, frac fluid). For non-well meters, the substitute composition should be as close to what is expected as reasonably possible. If the initial gas volume calculated by a substitute analysis is found to be in error by greater than 2% and the error volume is over 20 10^3 m^3/month, retroactive volumetric adjustments must be calculated using the initial gas composition.

Table 8.3. Sampling and analysis frequencies for various types of facilities

	Type of production battery/facility		Gas rate (10^3 m^3/d)	Sample and analysis type	Sampling point	Frequency
Gas wells/ batteries/ facilities	SE Alberta shallow gas zones/areas or coalbed methane well with minimal water (see 8.4.1)		N/A	Gas only	Group meter	Biennially
	Gas proration outside SE Alberta shallow gas zones /areas or effluent proration battery (see 8.4.2 & 8.4.3)		N/A	Gas/condensate	Test meters	At time of testing
					Group meter	Annually
	Multiwell group battery or single-well battery (including coalbed methane well/battery) with no condensate or oil (see 8.4.4)		N/A	Gas only	Per meter	Annual first year, then Biennially
	Multiwell group battery or single-well battery with condensate or oil (see 8.4.5)		> 16.9	Gas/condensate	Per meter	Annually
			≤ 16.9	Gas/condensate	Per meter	Biennially
	Gas storage schemes, injection and withdrawal phase (see 8.4.6)			Gas	Per injection/ production meter	First month, then semi-annually
	Gas cycling schemes (see 8.4.7)	Injection		Gas/condensate	Per injection meter	Per approval or source requirement (if not in approval)
		Production			Per production meter	Per approval or semi-annually (if not in approval)
	Gas sales/delivery (see 8.4.8)			Gas only	Per meter	Annually
	Gas plants (see 8.4.9)			Gas/condensate	Per accounting meter	Semiannually
	Gas gathering systems (see 8.4.9)		> 16.9	Gas/condensate	Per inlet meter	Annually
			≤ 16.9	Gas/condensate	Per inlet meter	Biennially
Conventional oil wells/ batteries	Single-well/ multiwell group battery (see 8.4.10)	Flared		Gas only	Per meter	Initial
		Conserved	> 16.9	Gas only	Per meter	Annually
			≤ 16.9	Gas only	Per meter	Biennially
	Multiwell proration battery	Primary production and water flood (see 8.4.11)	> 16.9	Gas only	Per test/group meter per pool	Annually
			≤ 16.9	Gas only	Per test/group meter per pool	Biennially
		Miscible/immiscible flood (see 8.4.12)	Production	Gas only	Per test/group meter	Per approval or quarterly (if not in approval)
			Injection		Per meter	Per approval or monthly (if not in approval)
Heavy oil/ crude bitumen batteries (see 8.4.13)	Single-well/ multiwell group battery		≤ 2.0	Gas only	Per well	Initial
			> 2.0	Gas only	Per meter	Biennially
	Multiwell proration battery		≤ 2.0	Gas only	Per meter/ Per pool	Initial
			> 2.0	Gas only	Per test/group meter	Biennially
Water source well/battery	Single-well/ multiwell battery			Gas only (if present)	Per well	Initial

Licensees must ensure that analysis data are used to update volumetric calculations by the end of the month following the receipt of the analysis report. The only exception is for effluent wells, for which the analysis must be updated by the end of the second month following receipt of the analysis report. If sampling and analysis are conducted for other purposes (e.g., joint venture and allocation agreements) more frequently than required by this directive, the licensee must use those data to update volumetric calculations.

8.4.1 Southeastern Alberta Shallow (SEA) Gas Zones/Areas or Coalbed Methane Wells (with Minimal Water)

In the configuration of Figure 8.1 of shallow gas wells or coalbed methane (CBM) wells with water production not more than 0.01 $m^3/10^3 m^3$ gas, analyses must be updated biennially at each group meter (Meter A). No sampling and analysis are required at the test meter or well. Density and component analysis data from the group meter sample point may be used for test meter calculations.

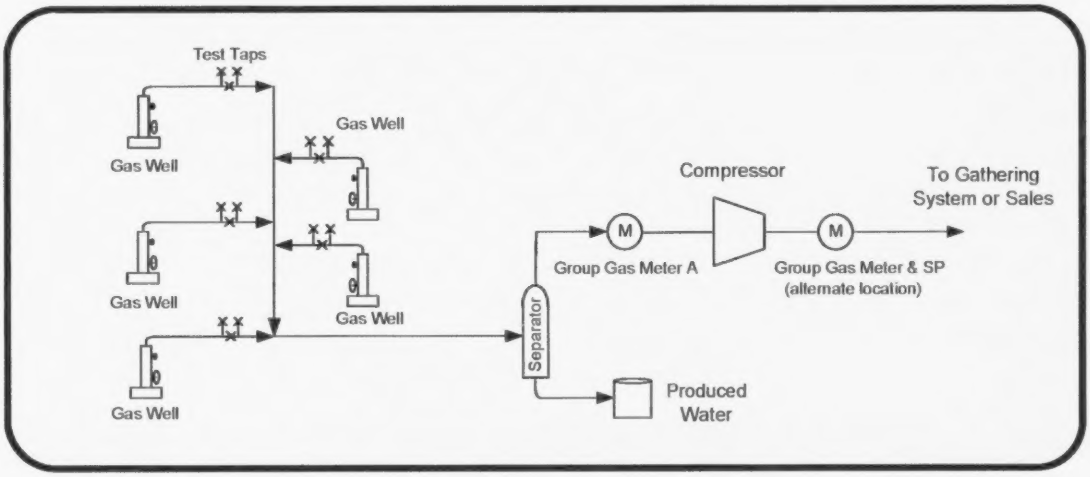

Figure 8.1

For coalbed methane wells that have been fractured or stimulated using a gaseous medium, gas samples must be taken monthly until the composition stabilizes and then biennially.

If these zones are commingled with gas from other outside zones, sampling must be done on a per pool/zone basis for CBM or per commingled SEA pool(s) basis from a representative well within the pool(s) biennially.

For exceptions on sampling for these pools/zones, see Section 8.4.2.

8.4.2 Gas Proration Outside SE Alberta Shallow Gas Zones/Areas (Excluding Effluent Proration Battery)

In the configuration in Figure 8.2, gas density and composition must be updated annually at each group meter (Meter A) and at each well during a test. If condensate at the group measurement point is recombined and delivered to a gas plant, the condensate GEF must be updated annually.

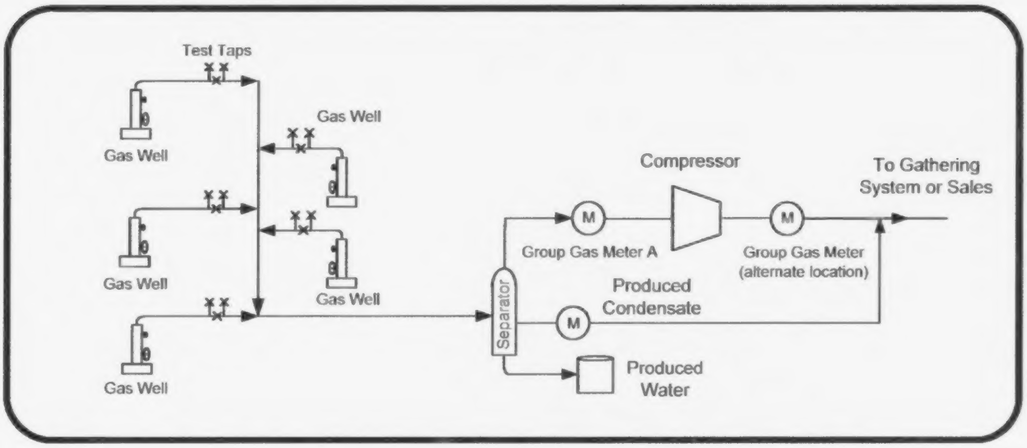
Test Taps
Gas Well
Gas Well
Gas Well
Gas Well
Gas Well
Compressor
To Gathering System or Sales
M
Group Gas Meter A
M
Group Gas Meter (alternate location)
Separator
M
Produced Condensate
Produced Water

Figure 8.2

Exceptions

1) A licensee is not required to update the analyses where three consecutive gas relative density (RD) determinations conducted at the specified determination frequency or, alternatively, no more frequently than once per year are all within ±1.0 per cent of the average of the three RDs (see Example 8.1). In this situation, there is no need for an application to be submitted to the ERCB. Records and data in support of this exception must be retained by the licensee and made available to the ERCB upon request. Notwithstanding this exception, the licensee must update the gas analyses when changes are made to producing conditions that could affect the gas density by more than ±1.0 per cent of the average of the three qualifying RDs.

2) The gas analyses determined at the group measurement points may be used for the test meters, provided that all wells are from the same pool.

Example 8.1

		Meter A
Sample date	RD	Difference from average
June 03, 2000	0.583	- 0.29%
June 09, 2001	0.586	+ 0.22%
June 06, 2002	0.585	+ 0.05%
Average	0.5847	

In this example, Meter A would be exempt from the requirement for future updates as the three consecutive RDs are within ±1.0 per cent of the average of the three RDs.

8.4.3 Multiwell Effluent Proration Battery

Wellhead Testing Sampling Points

In the configuration in Figure 8.4, gas analyses, condensate composition, and GEF must be updated at the time of testing each effluent well and annually at the group gas and condensate meters (see Figure 8.3). The gas analysis to be used for volumetric calculation at the effluent meter is as follows:

- Option 1: Use the separated gas analysis from the ECF-WGR test, or
- Option 2: Use the recombination of the gas analysis and the condensate analysis from the ECF-WGR test.

Note that all wells within the effluent battery must use the same analysis option.

Exceptions

A licensee is not required to update analyses at the group gas and condensate metering points if

- three consecutive gas RD determinations conducted at the specified determination frequency or no more frequently than once per year are all within ±1.0 per cent of the average of the three RDs (see Example 8.1), and
- the daily average liquid condensate volume is less than or equal to 2.0 m^3/d for all reporting months for the previous three years and/or the GEV of the condensate is less than or equal to 2.0 per cent of the recombined total monthly gas volume.

In these situations, there is no need for an application to be submitted to the ERCB. Records and data in support of these exceptions must be retained by the licensee and made available to the ERCB upon request. Notwithstanding these exceptions, the licensee must update the gas analyses when changes are made to producing conditions that could affect the gas RD by more than ±1.0 per cent of the average of the three qualifying RDs, and the licensee must update the condensate analyses if the liquid condensate volume or GEV percentage increases beyond the qualifying limits.

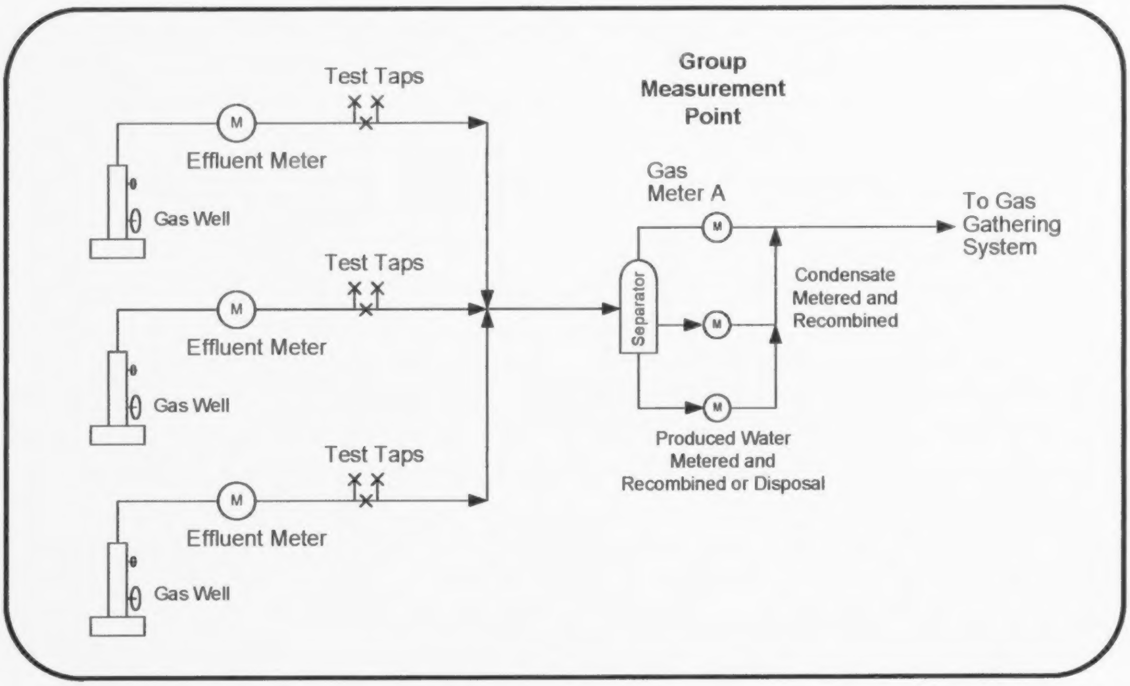
Test Taps
M
Effluent Meter
Gas Well
Test Taps
M
Effluent Meter
Gas Well
Test Taps
M
Effluent Meter
Gas Well
Group Measurement Point
Gas Meter A
M
Separator
M
M
To Gas Gathering System
Condensate Metered and Recombined
Produced Water Metered and Recombined or Disposal

Figure 8.3. Typical multiwell effluent proration battery

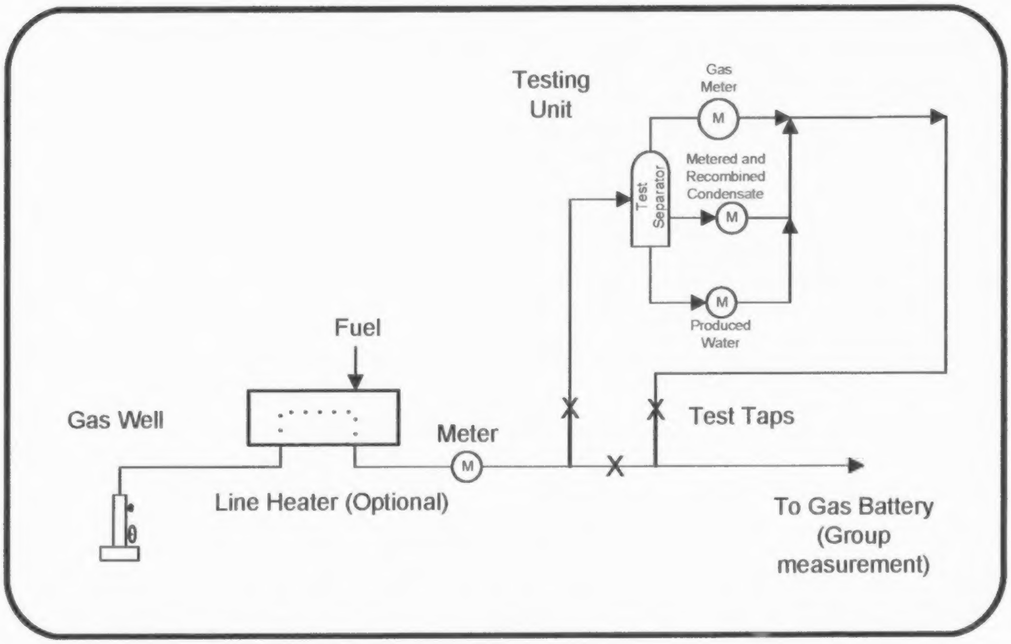
Testing Unit
Gas Meter
M
Test Separator
Metered and Recombined Condensate
M
M
Produced Water
Fuel
Gas Well
Meter
M
Test Taps
Line Heater (Optional)
To Gas Battery (Group measurement)

Figure 8.4. Typical effluent well testing configuration

8.4.4 Single Gas Well or Multiwell Group Gas Battery and Coalbed Methane Well with No Condensate or Oil

A "multiwell group" is a number of measured single gas wells all connected to a common delivery point.

For the configuration in Figure 8.5, the gas analysis must be updated within the first year and then biennially at each well meter (Meter A). For coalbed methane wells that have been fractured or stimulated using a gaseous medium, gas samples must be taken monthly until the composition stabilizes and then biennially.

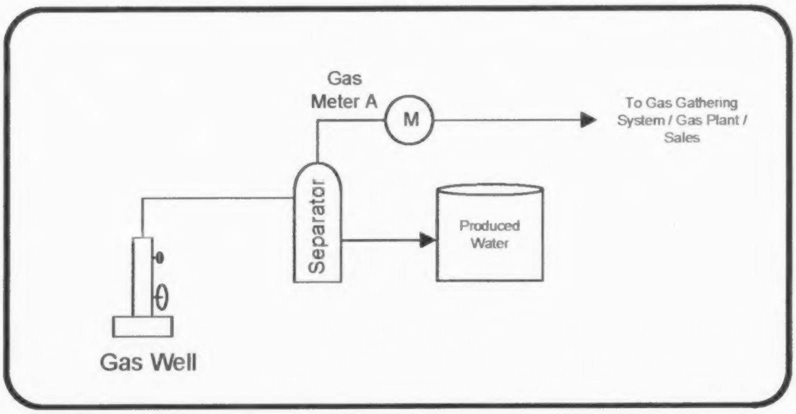
Gas Meter A
M
To Gas Gathering System / Gas Plant / Sales
Separator
Produced Water
Gas Well

Figure 8.5

Exceptions

1) A licensee is not required to update the analyses if three consecutive gas analyses conducted at the specified determination frequency or, alternatively, no more frequently than once per year are all within ±1.0 per cent of the average RD of the three analyses (see Example 8.1). In this situation, there is no need for an application to be submitted to the ERCB. Records and data in support of this exception must be retained by the licensee and made available to the ERCB upon request. Notwithstanding this exception, the licensee must update the gas analyses when changes are made to producing conditions that could affect the gas analysis by more than ±1.0 per cent of the average RD of the three qualifying analysis.

2) A representative analysis for all wells producing to a common gathering system or facility from a common pool can be used if the RD of all common-pool wells are within 2.0 per cent of the average analysis of those wells. Gas analyses must initially be obtained for all the common-pool wells to arrive at the average analysis. Subsequent analyses can be made on 25 per cent or at least four wells from the pool (whichever is greater) at the frequency stated in this directive, provided that the RD variance remains within the 2.0 per cent limit of these wells (see Example 8.2). Should the variance exceed this limit, this exception is revoked and biennial analyses must be determined for each measurement point.

Example 8.2

Consider an 8-well pool producing gas under the configuration below:

Well	RD	Difference from average
11-14	0.602	-0.99%
10-16	0.610	+0.33%
10-21	0.602	-0.99%
9-27	0.616	+1.32%
11-30	0.608	0.00%
6-31	0.616	+1.32%
11-32	0.606	-0.33%
11-16	0.604	-0.66%
Average	0.608	

In this case, it is acceptable to use the analyses from the well with the RD closest to the average (11-30) for all well meters, as all RDs are within ±2.0 per cent of the average of all well RDs. The analysis must then be updated biennially for at least four wells from the pool. This exception will remain in place, provided that all four well RDs continue to be within ±2.0 per cent of the average of all the updated RDs. When this criterion is not met, analyses must revert to biennial updates for all wells.

Permanent exception on a pool basis would be available where the updated average RD meets the criterion of Exception 1. Where practical, the ERCB expects the same wells to be used to arrive at the average RD used in pursuit of this exception.

8.4.5 Single Gas Well or Multiwell Group Gas Battery with Condensate or Oil

A "multiwell group" is a number of measured single gas wells all connected to a common delivery point.

For gas wells producing condensate in Figure 8.6, the frequency of sampling and analysis for gas and condensate depends upon the gas flow rate through Meter A plus the GEV of condensate. If the flow rate exceeds 16.9 10^3 m^3/d, the frequency is annual. If the flow rate is less than or equal to 16.9 10^3 m^3/d, the frequency is biennial. The flow rate is to be based on a monthly average.

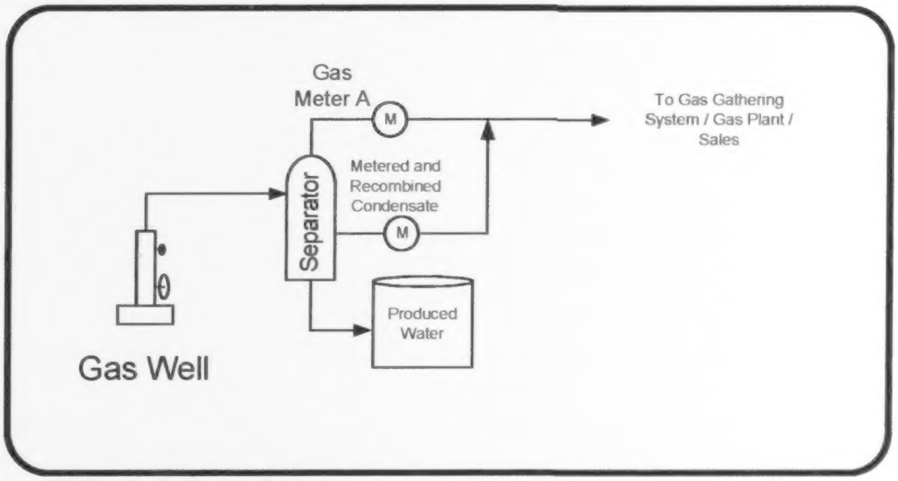
Gas
Meter A
M
To Gas Gathering System / Gas Plant / Sales
Metered and Recombined Condensate
M
Separator
Produced Water
Gas Well

Figure 8.6. Condensate production

For gas wells producing oil in Figure 8.7, the sampling and analysis of oil/emulsion streams to determine relative oil and water content must conform to the requirements in Section 6.4.3. The gas sampling frequency is the same as for a gas well producing condensate, except that the total gas flow rate does not include GEV of oil/emulsion.

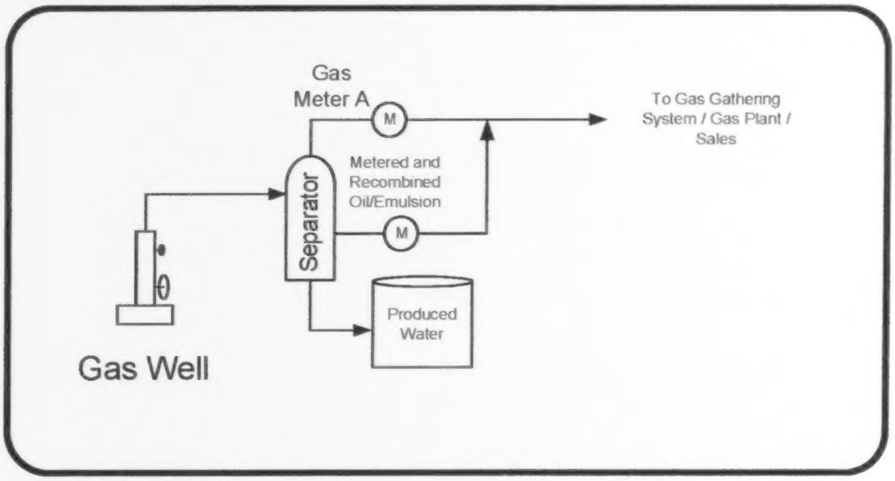
Gas
Meter A
M
To Gas Gathering System / Gas Plant / Sales
Metered and Recombined Oil/Emulsion
M
Separator
Produced Water
Gas Well

Figure 8.7. Oil production

Exceptions

1) For gas wells producing condensate, a licensee is not required to update the gas and condensate (if applicable) analyses at the metering points if

   - three consecutive gas RD determinations conducted at the specified determination frequency or no more frequently than once per year are all within ±1.0 per cent of the average of the three RDs (see Example 8.1), and
   - daily average liquid condensate volume is less than or equal to 2.0 m^3/d for all reporting months for the previous three years and/or the GEV of the condensate is less than or equal to 2.0 per cent of the recombined total monthly gas volume.

   In these situations, there is no need for an application to be submitted to the ERCB. Records and data in support of these exceptions must be retained by the licensee and made available to the ERCB upon request. Notwithstanding these exceptions, the licensee must update the gas analyses when changes are made to producing conditions that could affect the gas RD by more than ±1.0 per cent of the average of the three qualifying RDs, and the licensee must update the condensate analyses if the liquid condensate volume or GEV percentage increases beyond the qualifying limits.

2) A **representative** analysis for all wells producing to a common gathering system or facility **from a common pool** may be used if the RDs of all common-pool wells are within 2 per cent of the average RD of those wells. Gas analyses must initially be obtained for all the common-pool wells to arrive at the average RD. Subsequent analyses may be made on 25 per cent or at least four wells from the pool (whichever is greater) at the frequency stated in this directive, provided that the RD variance remains within the 2 per cent limit of these wells (see Example 8.2). Should the variance exceed this limit, this exception is revoked and biennial analyses must be determined for each measurement point.

8.4.6 Gas Storage Schemes

For the configuration in Figure 8.8, there are two phases to consider:

Injection Phase

If the injection gas only comes from a single source, an annual common stream sample analysis may be used for all injection meters, and no individual well injection analyses are required.

If there are multiple injection gas sources, sample analysis is required at each source stream and at each well injection measurement point. In this case, the minimum analysis frequency for injection meters are semiannual, however, a continuous proportional sampler or a gas chromatograph should be installed to provide more accurate compositions for gas volume calculations.

Withdrawal Phase

During each withdrawal phase, analyses must be updated at each well's (A, B, and C) production meters within the first month and semiannually thereafter if necessary.

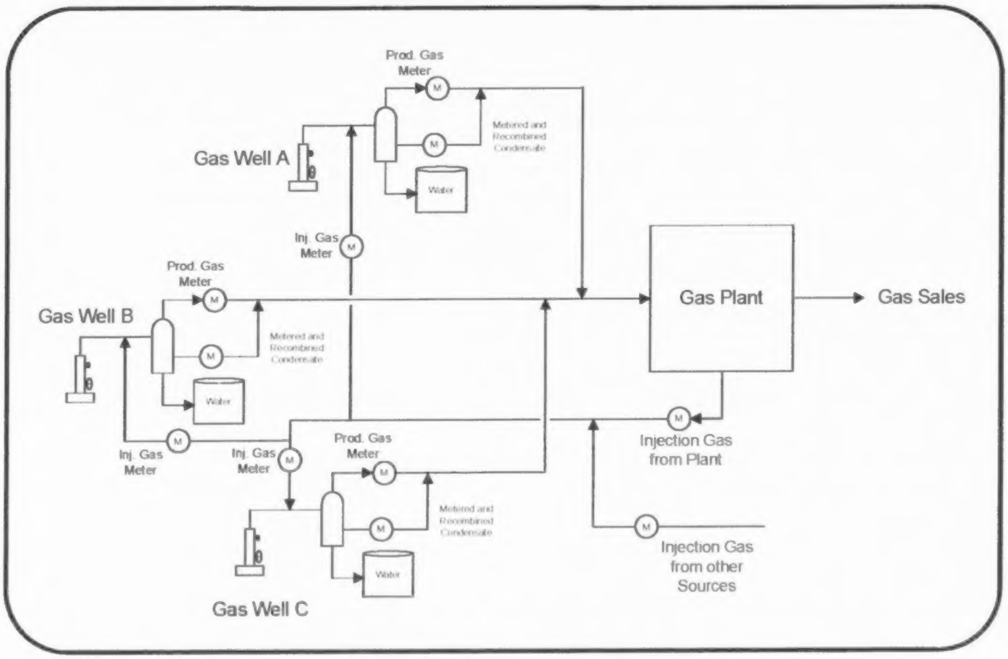
Prod. Gas Meter
Metered and Recombined Condensate
Gas Well A
Water
Inj. Gas Meter
Prod. Gas Meter
Gas Well B
Metered and Recombined Condensate
Water
Gas Plant
Gas Sales
Inj. Gas Meter
Inj. Gas Meter
Prod. Gas Meter
Injection Gas from Plant
Metered and Recombined Condensate
Water
Injection Gas from other Sources
Gas Well C

Figure 8.8

8.4.7 Gas Cycling Scheme

In the configuration in Figure 8.9, analyses must be updated at each well meter, A, B, and C, and the injection well meter in accordance with the specific scheme approval. If there are no frequencies specified in the approval, the well meters must have analyses updated semiannually and the gas injection meter(s) must have analyses updated in accordance with the source requirements (e.g., semiannually for gas plant gas).

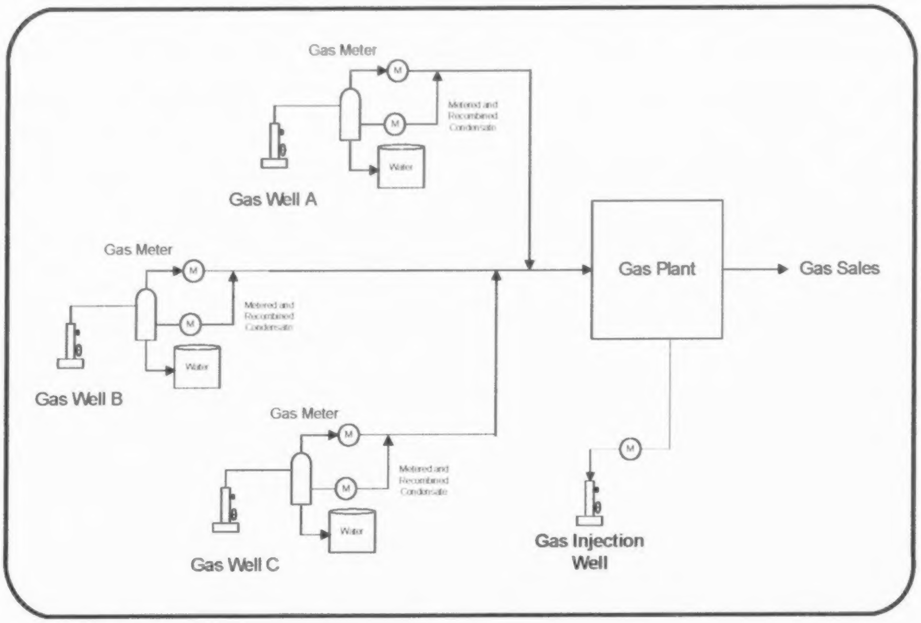
Gas Meter
Metered and Recombined Condensate
Water
Gas Well A
Gas Meter
Metered and Recombined Condensate
Water
Gas Well B
Gas Plant
Gas Sales
Gas Meter
Metered and Recombined Condensate
Water
Gas Well C
Gas Injection Well

Figure 8.9

8.4.8 Gas Sales/Delivery

In the configuration in Figure 8.10, gas sales/delivery in this context will typically be clean, processed sales gas that is delivered out of a gas plant or a facility into a transmission pipeline. The measurement at this point determines the gas volumes upon which royalties will be based. In some cases, this type of gas may be delivered to other plants for further processing or fuel or to injection facilities.

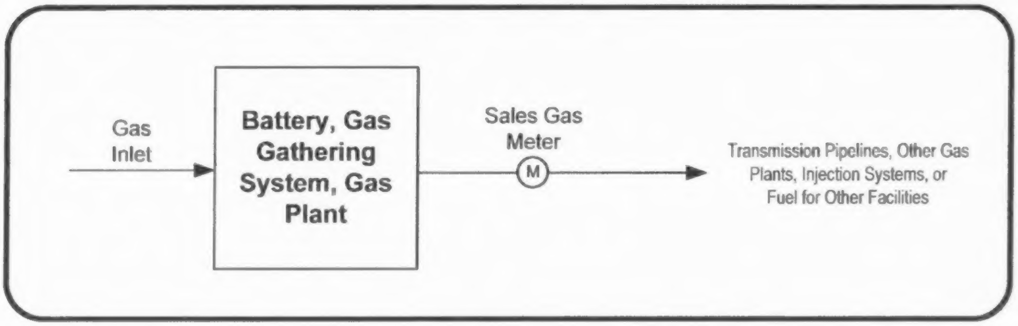
Gas Inlet
Battery, Gas Gathering System, Gas Plant
Sales Gas Meter
M
Transmission Pipelines, Other Gas Plants, Injection Systems, or Fuel for Other Facilities

Figure 8.10

If a meter is used to determine the sales gas/delivery point volume from a battery, gas gathering system, or gas plant, the minimum gas analysis frequency is annual. However, a continuous proportional sampler or a gas chromatograph should be installed to provide more accurate analyses for the gas volume calculation.

8.4.9 Gas Plants and Gas Gathering Systems

In the configuration in Figure 8.11, only one sample point is required for common gas streams, such as sales gas, which may also be used for fuel, injection, and sales gas flare. Inlet gas sample may be used for inlet gas flare.

The frequency for sampling and analysis is as follows unless a different frequency has been specified in site-specific approvals, such as gas cycling or miscible/immiscible flood schemes, or for heavy oil/crude bitumen gas production. For gas sales measurement point sampling frequency, see Section 8.4.8.

Gas Plant

The minimum frequency for updating analyses at all accounting meters within a gas plant is semiannual. Inlet condensate is reported as a GEV, so analyses are required. High-vapour pressure liquids, such as pentanes plus and NGL, are to be reported as liquid volumes on the PRA, which will then perform the GEV calculation automatically using standard factors for plant balancing.

Gas Gathering System

The minimum frequency for updating analyses at all accounting meters within a gas gathering system (GGS) is annual for all flow rates that exceed 16.9 10^3 m^3/d. If the flow rate is less than or equal to 16.9 10^3 m^3/d, the frequency is biennial. The flow rate is to be based on a monthly average. Condensate volumes recombined with gas for delivery to other facilities must be reported as GEV, so analyses are required for updating GEFs. Where condensate is delivered out of a GGS without further processing, it is reported as a liquid volume, but analyses for GEV calculation purposes are required for reporting to the PRA.

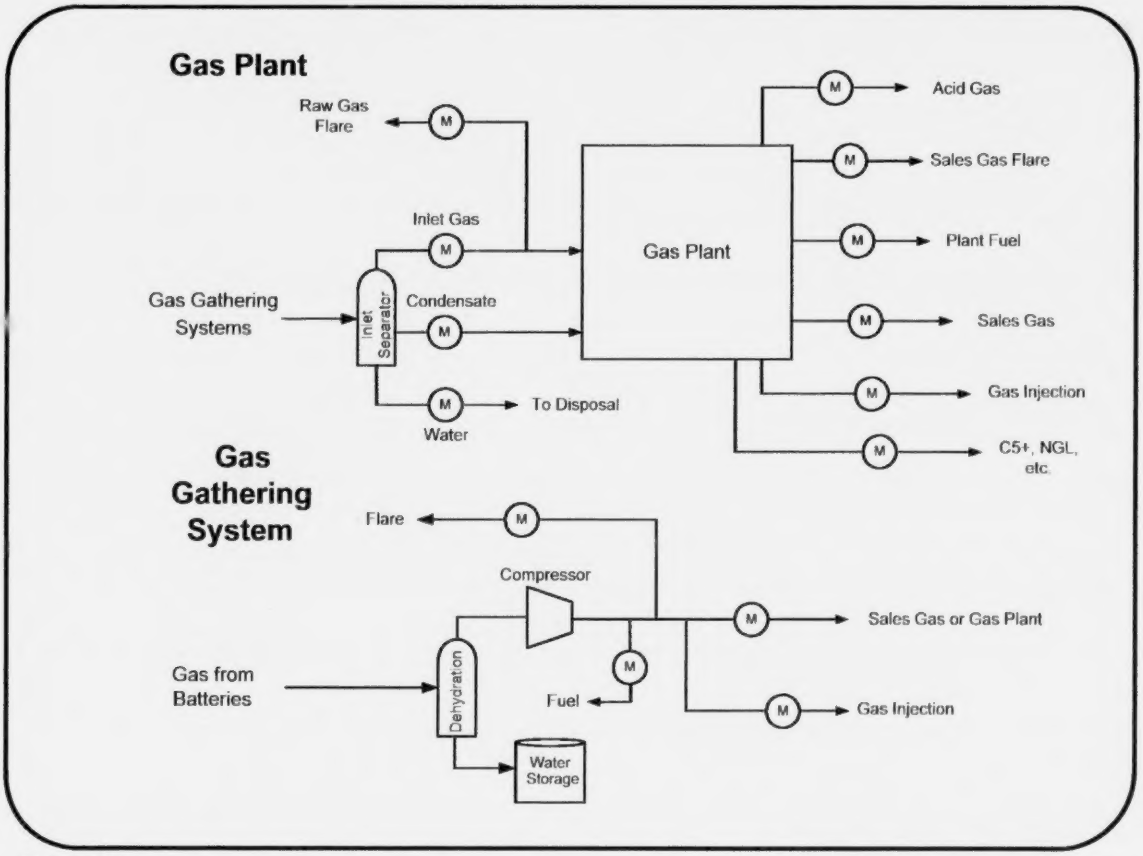
Gas Plant
Raw Gas Flare
M
Acid Gas
Sales Gas Flare
Inlet Gas
Gas Plant
Plant Fuel
Gas Gathering Systems
Inlet Separator
Condensate
Sales Gas
To Disposal
Water
Gas Injection
C5+, NGL, etc.
Gas Gathering System
Flare
Compressor
Sales Gas or Gas Plant
Gas from Batteries
Dehydration
Fuel
Gas Injection
Water Storage

Figure 8.11

8.4.10 Conventional Oil Facilities

In the configuration in Figure 8.12, if all solution gas (net of lease fuel) is flared, an initial representative gas analysis is required. If gas is conserved, gas analysis updates are required. If the average flow rate exceeds 16.9 10^3 m^3/d, the frequency is annual. If the average flow rate is less than or equal to 16.9 10^3 m^3/d, the frequency is biennial.

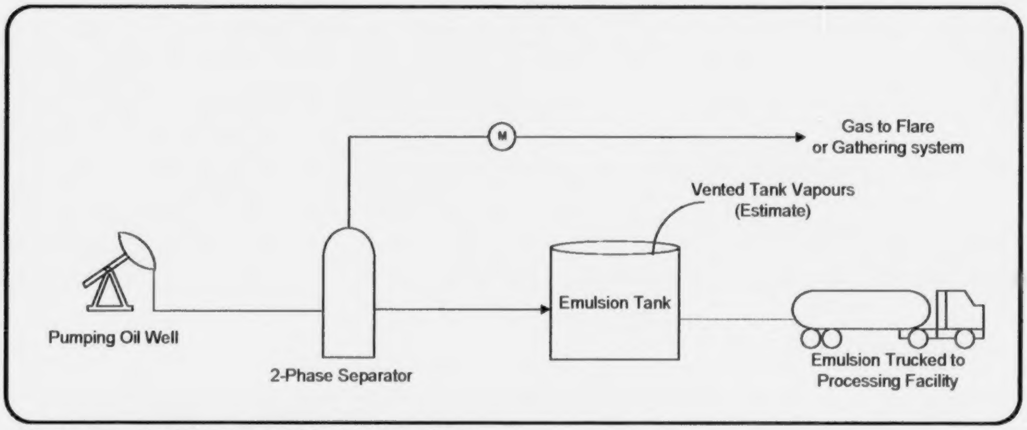
M
Gas to Flare or Gathering system
Vented Tank Vapours (Estimate)
Emulsion Tank
Pumping Oil Well
2-Phase Separator
Emulsion Trucked to Processing Facility

Figure 8.12. Single-well or multiwell group oil battery

8.4.11 Multiwell Proration Oil Battery

In the configuration in Figure 8.13, the gas analyses must be updated at the test meters (A and B) biennially for maximum test gas rates up to 16.9 10^3 m^3/d or annually if the maximum test gas rates exceed 16.9 10^3 m^3/d.

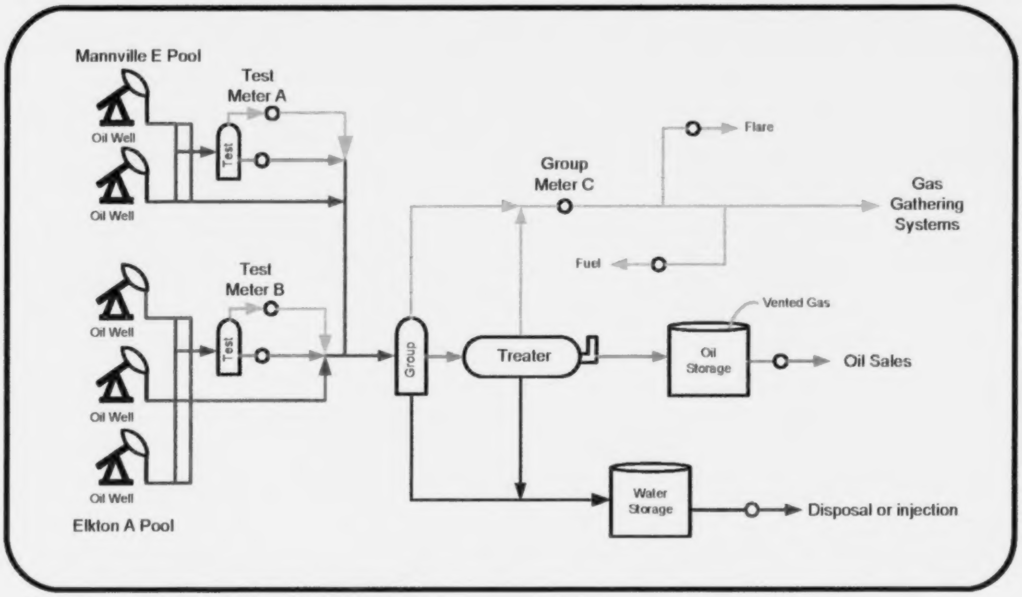
Mannville E Pool
Test Meter A
Oil Well
Test
Oil Well
Flare
Group Meter C
Gas Gathering Systems
Fuel
Test Meter B
Vented Gas
Oil Well
Test
Group
Treater
Oil Storage
Oil Sales
Oil Well
Oil Well
Water Storage
Disposal or injection
Elkton A Pool

Figure 8.13. Primary production/water flood

It is acceptable to use the gas analysis from a single representative well for all wells within a single pool. If wells from more than one pool are directed through the same test separator, an analysis must be obtained for each pool.

The gas analysis at meter C must be updated annually for gas flow rates exceeding 16.9 10^3 m^3/d or biennially if the total rate through the meter is less than or equal to 16.9 10^3 m^3/d (based on the monthly average flow rate).

Example 8.3

Consider a 5-well proration battery with two wells producing from the Mannville E Pool and three wells producing from the Elkton A Pool. Battery gas production is gathered and conserved.

Pool	Well	Satellite meter	Test gas rate (10^3 m^3/d)
Mannville E	10-14	Meter A	4.2
Mannville E	10-16	Meter A	6.8
Elkton A	10-21	Meter B	18.0
Elkton A	9-27	Meter B	12.0
Elkton A	10-30	Meter B	6.5
		Total rate for Meter C =	47.5

A gas analysis must be established for the Mannville E Pool, as a minimum using either the 10-14 or 10-16 well, and updated biennially at meter A, as the maximum rate through meter A for the Mannville E pool wells is less than 16.9 10^3 m^3/d.

A gas analysis must be determined for the Elkton A Pool at meter B, as a minimum using any one of the three wells, and updated annually, as the maximum rate through meter B for the Elkton A pool wells is greater than 16.9 10^3 m^3/d.

The gas analysis at meter C must be updated annually, as the flow rate through the meter exceeds 16.9 10^3 m^3/d.

Exception

If the total battery gas, net of lease fuel, is flared, an initial pool gas analysis must be determined at meters A and B. Updates of the gas analysis at meter C, at the annual or biennial frequency as determined by the gas flow rate through the meter, is only required if the gas directed through meter C originates from multiple pools. If the gas directed through meter C originates from a single pool, no updates are required subsequent to the initial analysis. However, this exception is revoked as soon as the gas is conserved, and gas analyses must be performed according to the frequencies specified above.

8.4.12 Miscible/Immiscible Flood

In the configuration in Figure 8.14, analyses must be updated at each test and group meter and the injection well meter in accordance with the specific scheme approval. If there are no frequencies specified in the approval, the sampling frequency must be updated in accordance with the requirements in *IL 92-05*. That is, the test and group meters must have analyses updated quarterly and the injection meter(s) must have analyses updated monthly.

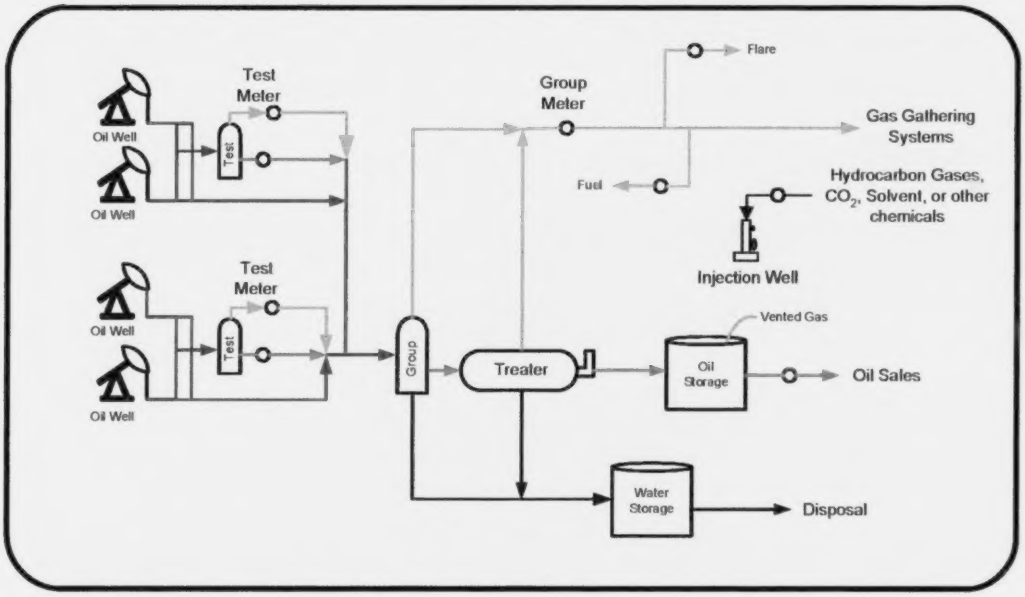
Flare
Test Meter
Group Meter
Gas Gathering Systems
Oil Well
Test
Oil Well
Fuel
Hydrocarbon Gases, CO_2, Solvent, or other chemicals
Injection Well
Test Meter
Oil Well
Test
Oil Well
Vented Gas
Group
Treater
Oil Storage
Oil Sales
Water Storage
Disposal

Figure 8.14

8.4.13 Heavy Oil/Crude Bitumen Facilities

Heavy oil/crude bitumen production at a single-well (Figure 8.15) or multiwell group battery (Figure 8.16) typically involves directing all production to a tank without using a separator or gas meter. In such cases, gas production may be estimated using a GOR. If a meter is used to measure gas for the purposes of conducting GOR tests or continuous gas production measurement, an initial gas analysis is required. An analysis from a comparable well producing from the same pool may be used if a meter will be used to measure gas to determine GOR.

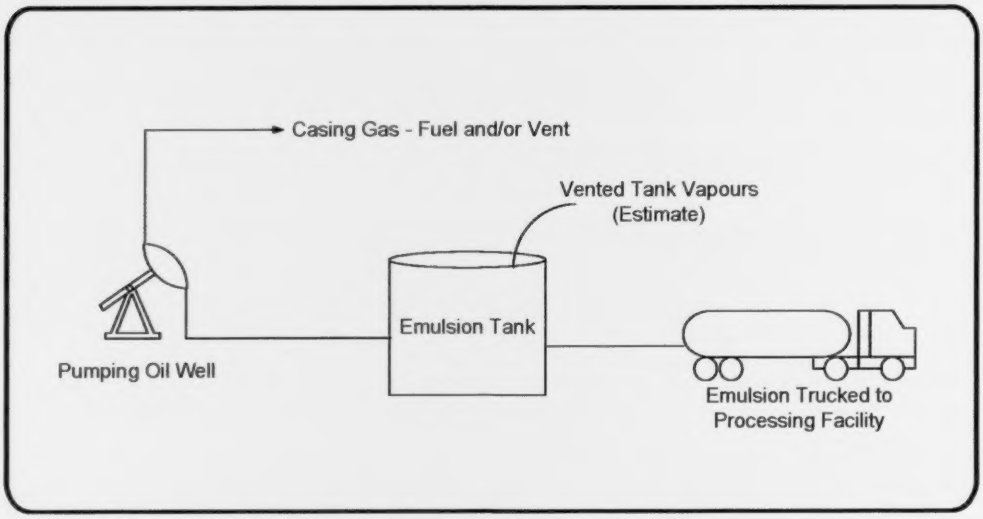
Casing Gas - Fuel and/or Vent
Vented Tank Vapours (Estimate)
Emulsion Tank
Pumping Oil Well
Emulsion Trucked to Processing Facility

Figure 8.15. Heavy oil/crude bitumen single-well battery

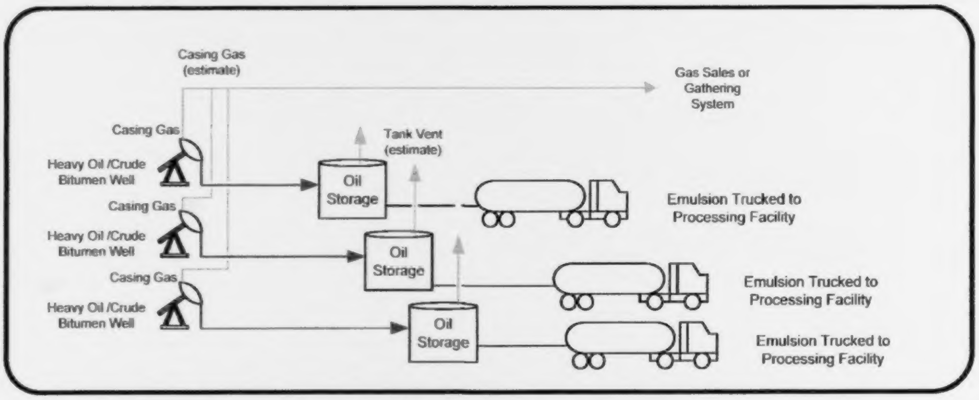
Casing Gas (estimate)
Gas Sales or Gathering System
Casing Gas
Heavy Oil /Crude Bitumen Well
Tank Vent (estimate)
Oil Storage
Emulsion Trucked to Processing Facility
Casing Gas
Heavy Oil /Crude Bitumen Well
Oil Storage
Emulsion Trucked to Processing Facility
Casing Gas
Heavy Oil /Crude Bitumen Well
Oil Storage
Emulsion Trucked to Processing Facility

Figure 8.16. Heavy oil/crude bitumen multiwell group battery

If a GOR is determined by methods other than using gas measurement, an initial gas analysis is not required.

If a meter is used to measure gas on a continuous basis, biennial analysis updates are required.

Heavy oil/crude bitumen production at multiwell proration batteries (Figure 8.17) may involve directing all production to tanks without using separators or gas meters, but if combined gas volumes meet the economic requirements in *Directive 060*, the gas must be gathered and conserved.

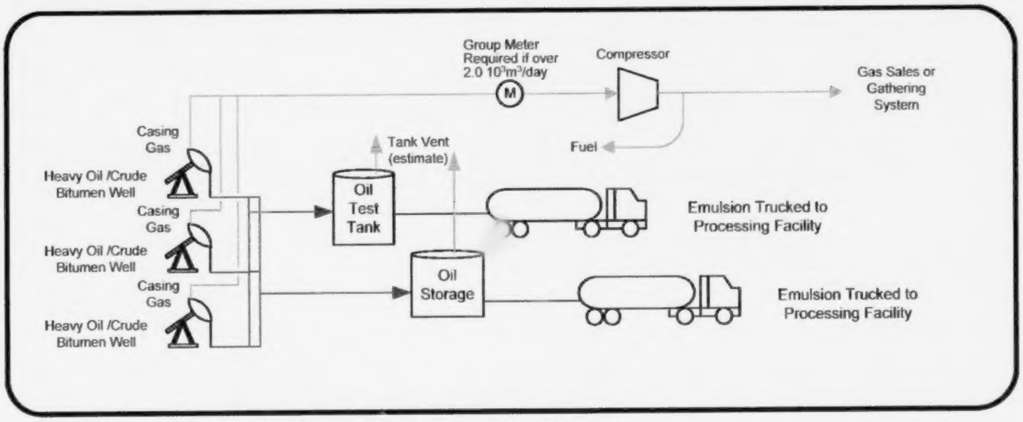
Group Meter
Required if over
2.0 10³m³/day
M
Compressor
Gas Sales or
Gathering
System
Casing
Gas
Heavy Oil /Crude
Bitumen Well
Tank Vent
(estimate)
Fuel
Oil
Test
Tank
Emulsion Trucked to
Processing Facility
Casing
Gas
Heavy Oil /Crude
Bitumen Well
Oil
Storage
Casing
Gas
Emulsion Trucked to
Processing Facility
Heavy Oil /Crude
Bitumen Well

Figure 8.17. Heavy oil/crude bitumen multiwell proration battery

If a meter is used to measure gas for the purposes of conducting GOR tests, an initial gas analysis is required. If a GOR is determined by methods other than using gas measurement, an initial gas analysis is not required.

If a meter is used to measure gas on a continuous basis, biennial analysis updates are required.

9 Cross-Border Measurement

This section presents the measurement requirements for all upstream and midstream oil and gas production crossing a provincial or territorial border.

9.1 General Requirements

For those facilities receiving non-Alberta production and/or delivering Alberta production to another jurisdiction either by trucking or pipeline, including pipelines under the National Energy Board (NEB) jurisdiction, each jurisdictional production stream must be isolated and measured prior to commingling. The delivery point measurement standards for Alberta and that of the other jurisdictional authority(ies) must be followed, unless site-specific approval from the ERCB and the other jurisdictional authority(ies) has been obtained. All streams must be isolated and measured or estimated according to requirements in this directive. This could include production and gathering systems, all fuel, flare, and vent. If the measurement or other equipment requirement for delivery point measurement of hydrocarbon and related fluids from any jurisdiction is different from the Alberta requirements, the higher requirements, such as frequency and accuracy, between the jurisdictions must be followed.

"Non-Royalty Exempt Fuel Gas" usage at a cross-border oil and gas processing facility must be separately determined and measured if it is over 0.5 10^3 m^3/d for each jurisdiction. If the usage is for production from both jurisdictions or site-specific approval is obtained from both jurisdictions involved, no separate fuel gas metering is required. For example, a compressor used only for gas coming from another jurisdiction into Alberta must be metered separately at the cross-border facility and the fuel gas use for other equipment processing commingled production or the entire facility must be measured with another meter.

9.2 Cross-Border Sampling Requirements

Except where otherwise noted, the gas and liquid sampling equipment and methodology must follow the requirements set out in Section 8: Gas and Liquid Sampling and Analysis.

Spot or grab samples are acceptable for obtaining gas and liquid analyses, provided the uncertainty requirements in Section 1 of *Directive 017* are fulfilled.

When the uncertainty requirements cannot be met, consider

- more frequent spot sampling for calculated analysis,
- the use of proportional samplers, or
- the use of gas chromatographs or other continuous analyzers.

9.3 Cross-Border Measurement Points

Figures 9.1 through 9.9 are some (not an exhaustive set) of the production scenarios to determine if a specific circumstance is considered "cross border." Each scenario applies as well if the flow is in the opposite direction. There must be only one cross-border measurement point for each pipeline crossing the provincial boundary unless site-specific approval is obtained from both jurisdictions involved.

The cross-border measurement point can be on either side of the jurisdictional border before commingling with any fluids from another jurisdiction. Measurement-by-difference rules apply in all cases where there is measured production going into a proration battery.

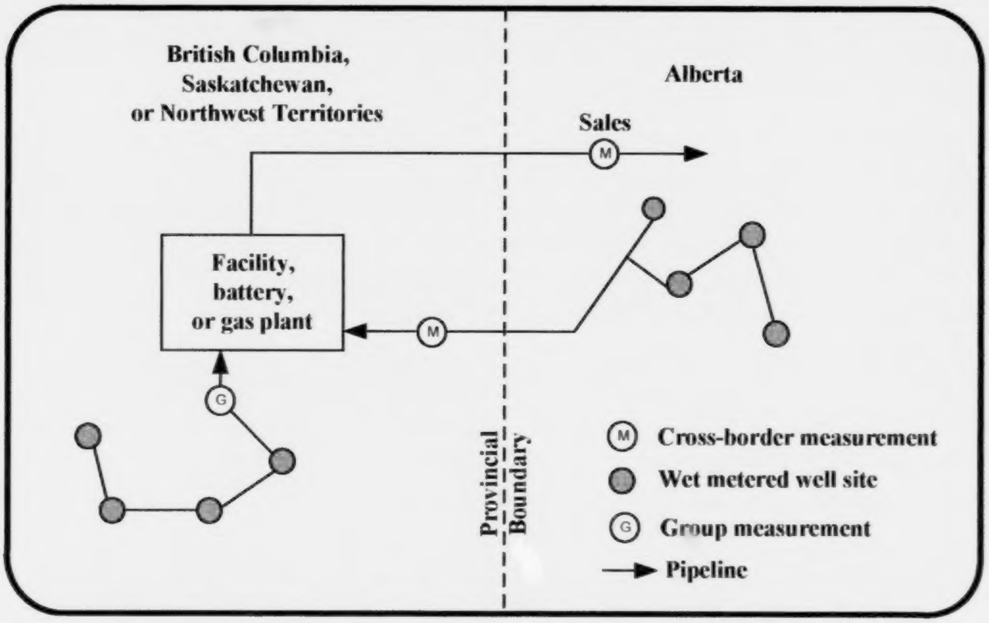
British Columbia,
Saskatchewan,
or Northwest Territories
Alberta
Sales
M
Facility,
battery,
or gas plant
M
G
Provincial Boundary
M Cross-border measurement
Wet metered well site
G Group measurement
Pipeline

Figure 9.1. Wet gas measured wells to an out-of-province location (non-common pool)

For cross-border common pools producing from one or more jurisdictions, if the surface facility is located in one jurisdiction and the well production as defined by the bottomhole location is in another jurisdiction, delivery point measurement of the production is required (see Figure 9.2). The production from this well must be reported as delivered to the other jurisdiction where the surface facility is located.

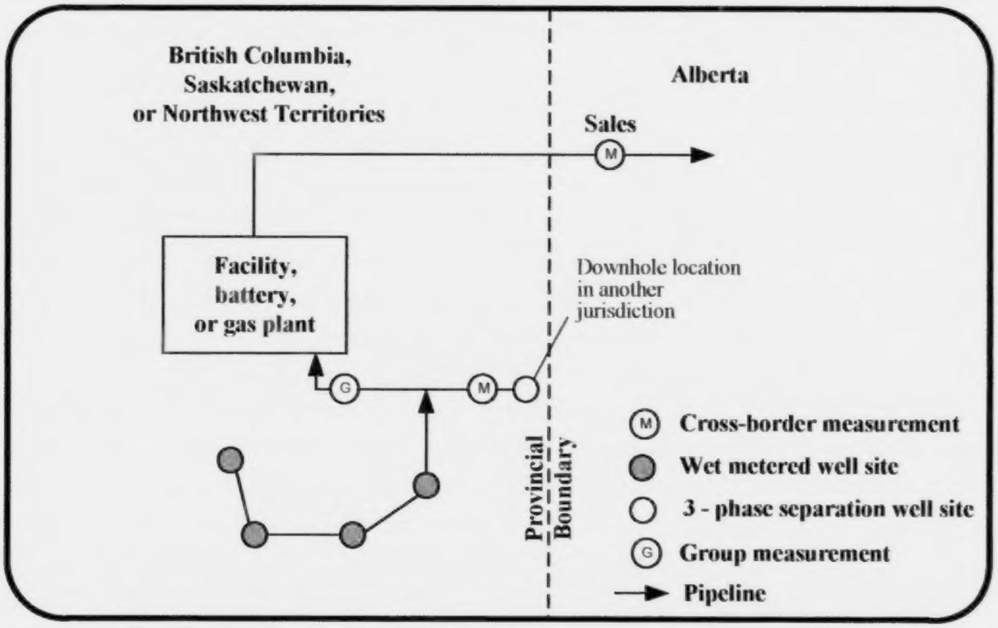
British Columbia,
Saskatchewan,
or Northwest Territories
Alberta
Sales
M
Facility,
battery,
or gas plant
Downhole location
in another
jurisdiction
G
M
Provincial Boundary
M Cross-border measurement
Wet metered well site
3 - phase separation well site
G Group measurement
Pipeline

Figure 9.2. Gas gathering system of wet gas measured well with measured well downhole location in another jurisdiction

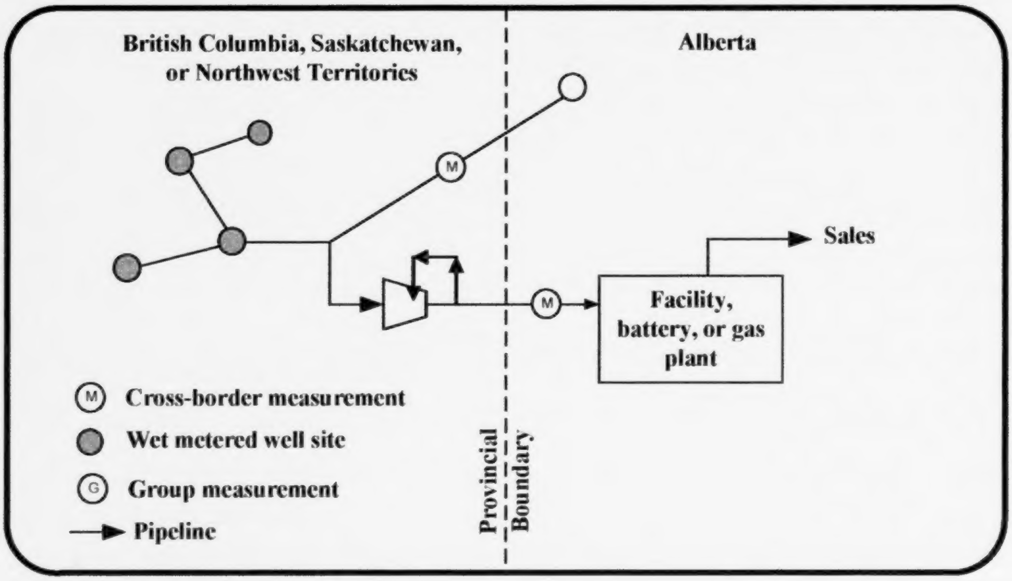
British Columbia, Saskatchewan, or Northwest Territories
Alberta
M
Sales
M
Facility, battery, or gas plant
M Cross-border measurement
Wet metered well site
G Group measurement
Pipeline
Provincial Boundary

Figure 9.3. Multiple jurisdictional crossing

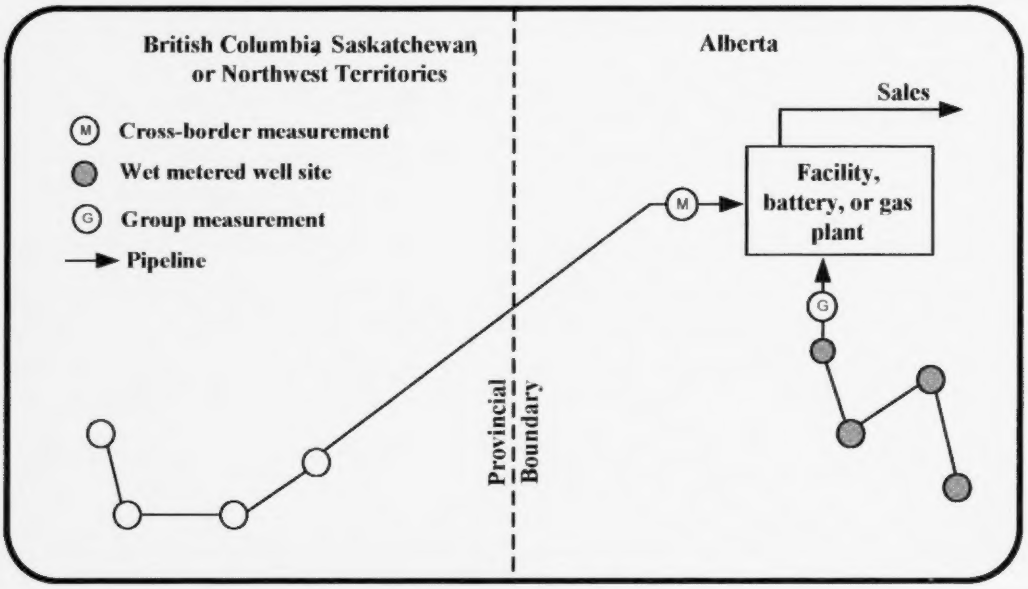
British Columbia, Saskatchewan, or Northwest Territories
Alberta
Sales
M Cross-border measurement
Wet metered well site
G Group measurement
Pipeline
M
Facility, battery, or gas plant
G
Provincial Boundary

Figure 9.4. Measured gas source from an out-of-province location

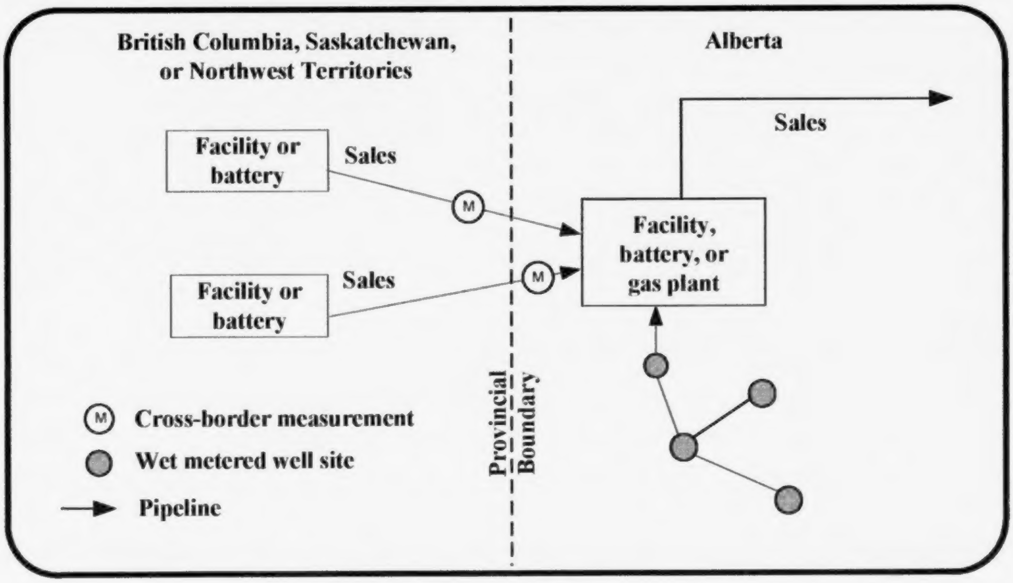
British Columbia, Saskatchewan, or Northwest Territories
Alberta
Facility or battery
Sales
M
Facility or battery
Sales
M
Facility, battery, or gas plant
Sales
Provincial Boundary
M Cross-border measurement
Wet metered well site
Pipeline

Figure 9.5. Sales gas source from an out-of-province location

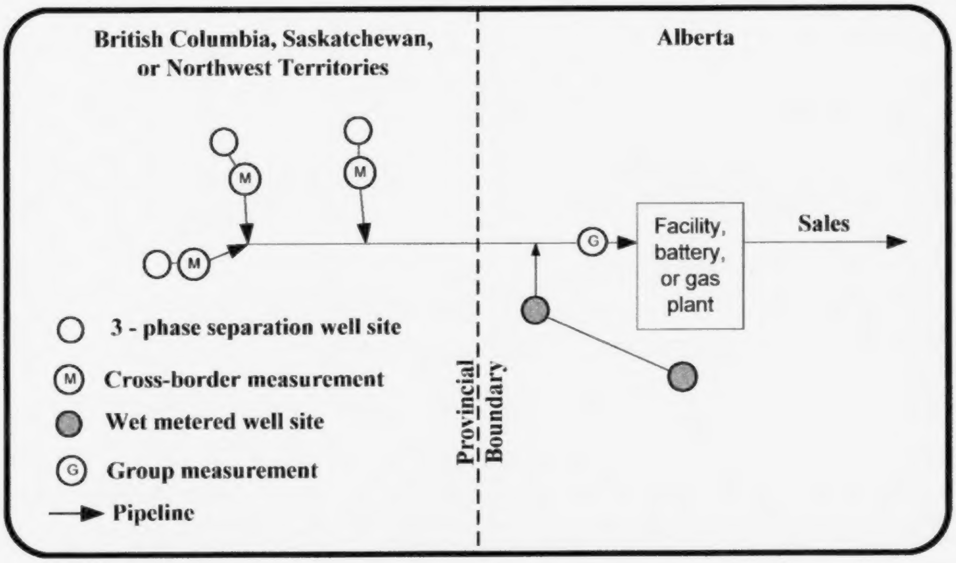
British Columbia, Saskatchewan, or Northwest Territories
Alberta
M
M
M
G
Facility, battery, or gas plant
Sales
3 - phase separation well site
M Cross-border measurement
Wet metered well site
G Group measurement
Pipeline
Provincial Boundary

Figure 9.6. Measured sources from an out-of-province location

For Figure 9.6, the three-phase separation at the well site can be designed to delivery point measurement requirements without another cross-border measurement point.

Measurement-by-difference rules applies in Figures 9.1, 9.2, 9.4, 9.5, and 9.6 unless the wet metered wells have a group measurement point prior to commingling with the measured gas source(s).

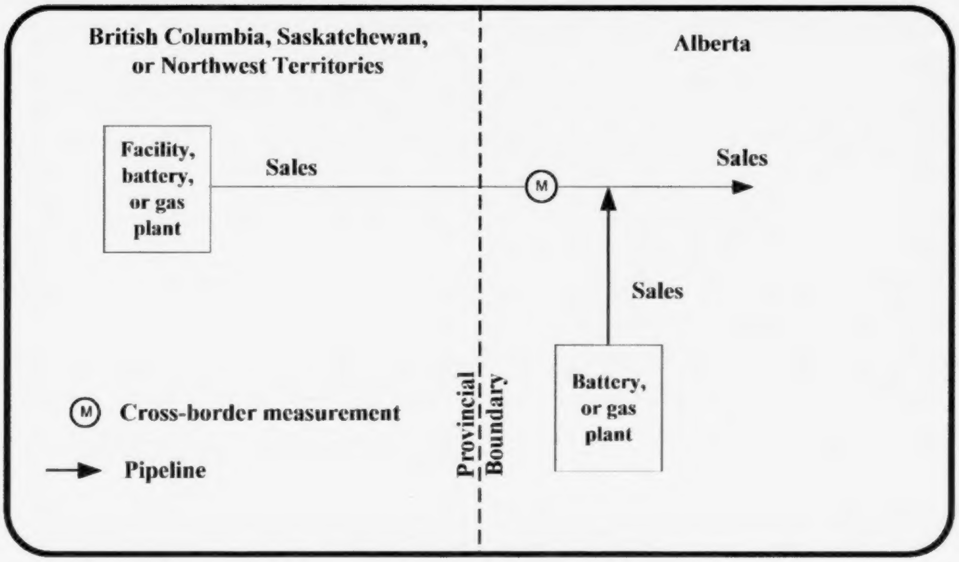
British Columbia, Saskatchewan, or Northwest Territories
Alberta
Facility, battery, or gas plant
Sales
M
Sales
Sales
Battery, or gas plant
Provincial Boundary
M Cross-border measurement
Pipeline

Figure 9.7. Sales oil or gas source from an out-of-province location

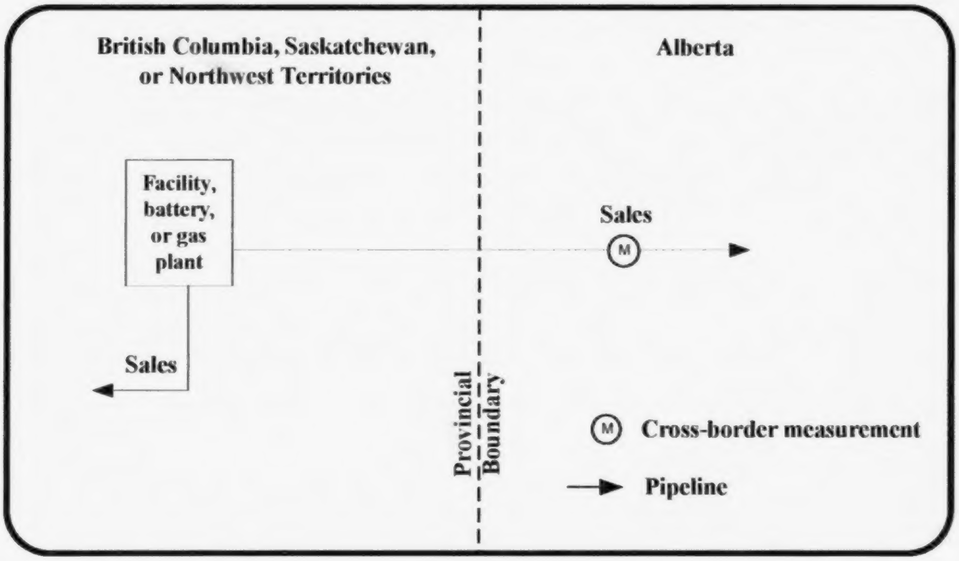
British Columbia, Saskatchewan, or Northwest Territories
Alberta
Facility, battery, or gas plant
Sales
M
Sales
Provincial Boundary
M Cross-border measurement
Pipeline

Figure 9.8. Sales oil or gas source from an out-of-province location

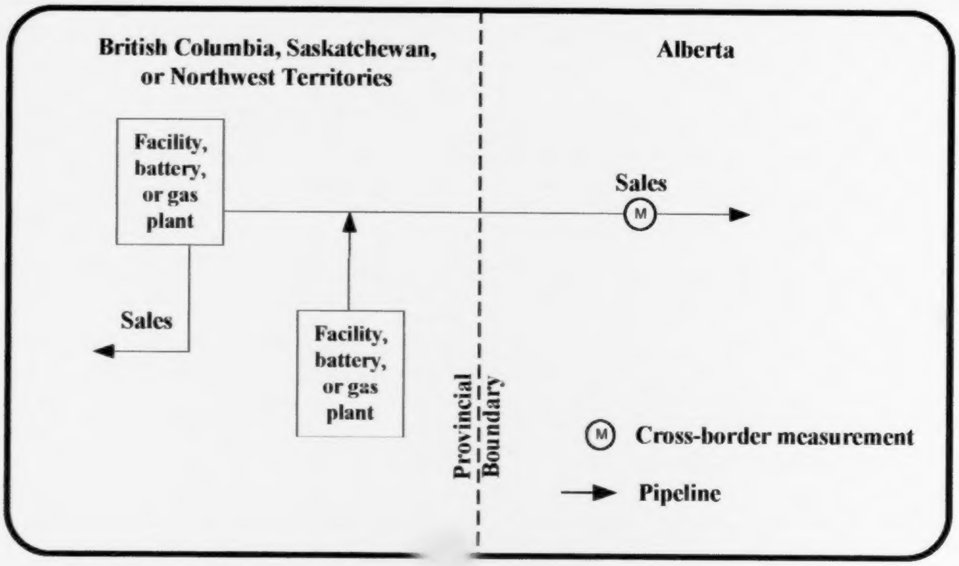
British Columbia, Saskatchewan, or Northwest Territories
Alberta
Facility, battery, or gas plant
Sales
Facility, battery, or gas plant
Sales
M
Provincial Boundary
M Cross-border measurement
Pipeline

Figure 9.9. Sales oil or gas source from an out-of-province location

10 Trucked Liquid Measurement

This section presents the requirements for trucked liquid measurement from oil and gas production facilities to another facility or sales. Applicable liquids include oil, condensate, water, NGLs, propane, butane, and crude bitumen.

10.1 General Requirements

Crude oil or condensate may be found in association with water in an emulsion. In such cases, the total liquid volume of the trucked load must be measured, and the relative volumes of oil and water in the emulsion must be determined by obtaining and analyzing a representative sample of the emulsion or by using a product analyzer such as a water-cut monitor or a Coriolis meter's density measurement (where applicable).

A licensee must accurately measure produced liquids/emulsion volumes by using tank gauging, a weigh scale, or a meter, unless otherwise stated in this directive. The delivery point measurement requirements must be met for all trucked liquids unless the exception conditions in this section are met or site-specific approval from the ERCB has been obtained.

The ERCB will consider a truck liquid measurement system to be in compliance if the following base requirements are met. The ERCB may stipulate additional or alternative requirements for any specific situation, based on a site-specific assessment.

All delivery point meters must be proved in accordance with Section 2. LACT meters may use the proving procedure in API-MPMS, Chapter 4: Proving Systems, instead of the Section 2 procedure.

10.1.1 Reporting Requirements

Monthly oil, condensate, and water volumes for well(s) (production) and battery(s) (production, receipts, and dispositions) must be reported as the number of cubic metres rounded to the nearest tenth of a cubic metre (0.1 m^3). Measured volumes must be corrected to 15°C and at the greater of 0 kPag or equilibrium vapour pressure at 15°C. See Section 6.3.3 for production data verification and audit trail requirements.

For delivery point measurement, hydrocarbon liquid volume must be determined to 2 decimal places and rounded to 1 decimal place for monthly reporting. If there is more than one volume determination within the month at a reporting point, the volumes determined to 2 decimal places must be totalled prior to the total being rounded to 1 decimal place for reporting purposes.

10.1.2 Temperature Correction Requirements

All delivery point measurement of hydrocarbons and emulsions requires temperature correction to 15°C (see Section 6.3.1.1). See Section 6.3.2.1 for temperature determination requirements. Composite meter factors are not acceptable for delivery point measurements.

The temperature correction factor (CTL) must be determined in accordance with the API MPMS, Chapter 11.1. LPG must follow the applicable GPA Technical Publication TP-27 or an equivalent industry standard.

10.1.3 Pressure Correction Requirements

The pressure correction factor (CPL) must be determined in accordance with API MPMS, Chapter 11, and is required only for LACT applications.

10.2 General Trucked Liquid Measurement, Accounting, and Reporting Requirements for Various Facility Types

10.2.1 Conventional Oil Batteries

For trucked oil/emulsion production into an oil battery, delivery point measurement is required for the total liquid volume. If there is a mixture of trucked-in production and prorated production within the same battery, the exception criteria in Section 5.5.2 must be met or ERCB site-specific approval must be obtained.

For condensate trucked into an oil battery, delivery point measurement is required for the total liquid volume. The requirements in Section 6.6 must be met.

For any oil battery, the trucked-out liquid is measured at the delivery point (located at the receiving facility), and the oil volume determined at the receiving facility must be used as the delivering battery's oil disposition. Proper measurement must be set up at the receipt point only, except for load oil delivery from a facility to well(s). In this case, delivery point measurement is required at the loading facility. If there are emergencies or problems at the receipt point, the origin measurement may be used, but only as a temporary solution.

If clean oil from a battery (BT) is delivered into an oil pipeline via a LACT unit and that same BT also receives clean trucked oil, condensate, or diluent from other sources with delivery point measurement, a terminal (TM) PRA code must be obtained so that the clean trucked-in fluid is received at the TM instead of at the BT. The BT oil must also be measured with delivery point measurement before commingling with other fluids at the TM. The TM will then deliver the fluid to the pipeline via the LACT unit. If there is no delivery point measurement for the BT oil to the TM, measurement by difference rules apply (see Section 5.5). The Alberta Petroleum Marketing Commission (APMC) can then allocate royalty and oil equalizations to all the oil receipt volumes at the TM. (See Figure 10.1)

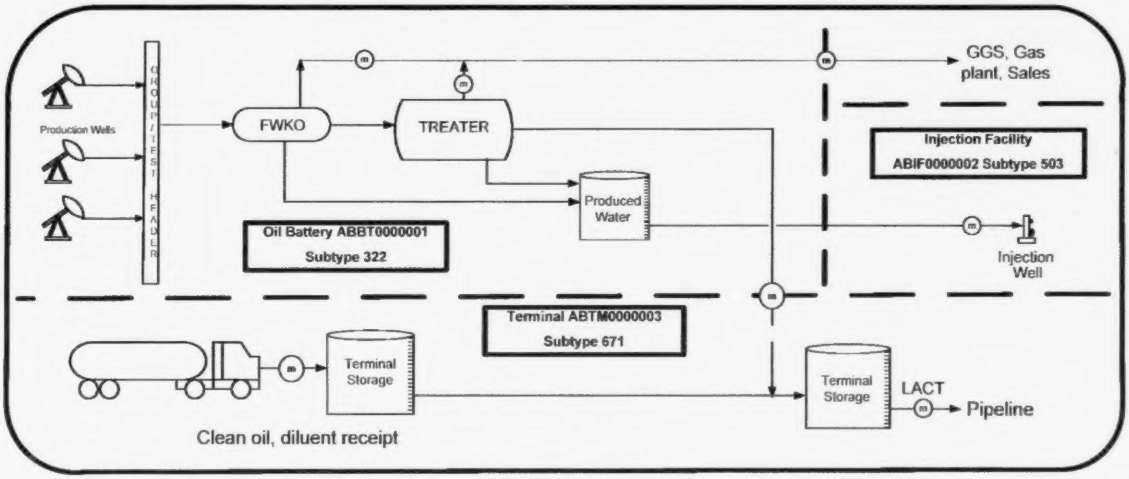
Production Wells
GROUP/TEST HEADER
FWKO
TREATER
m
GGS, Gas plant, Sales
Injection Facility
ABIF0000002 Subtype 503
Produced Water
Oil Battery ABBT0000001
Subtype 322
Injection Well
Terminal ABTM0000003
Subtype 671
Terminal Storage
Terminal Storage
LACT
Pipeline
Clean oil, diluent receipt

Figure 10.1. Oil battery and terminal schematic

Custom Treating, Oil Battery, and Terminal Delineation

A terminal is required when there is more than one source of clean oil going through a LACT meter into an oil pipeline. Any oil, water, and gas crossing a facility boundary must be measured. If there is blending of hydrocarbon liquids of densities >40 kg/m^3, such as butane blending with the oil before the LACT, the lighter hydrocarbon used for blending must be received and stored at the terminal and the oil production measured before the blending point.

Scenario 1: Dedicated tankage for clean crude and produced water for both the crude proration battery and the custom treating battery.

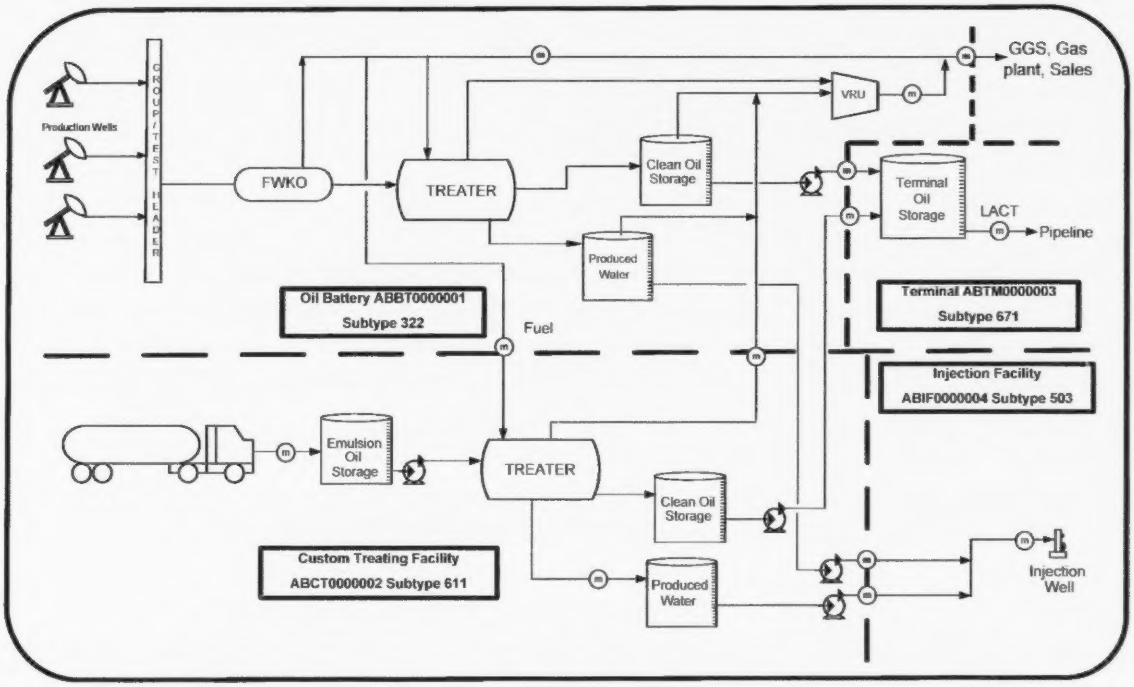
Production Wells
GROUP/TEST HEADER
FWKO
TREATER
m
GGS, Gas plant, Sales
VRU
Clean Oil Storage
Terminal Oil Storage
LACT
Pipeline
Produced Water
Oil Battery ABBT0000001
Subtype 322
Terminal ABTM0000003
Subtype 671
Fuel
Injection Facility
ABIF0000004 Subtype 503
Emulsion Oil Storage
TREATER
Clean Oil Storage
Custom Treating Facility
ABCT0000002 Subtype 611
Produced Water
Injection Well

Figure 10.2. Custom treating, oil battery, and terminal schematic – scenario 1

Scenario 2: Dedicated metering on treaters for water/oil and a shared tank for clean crude and produced water.

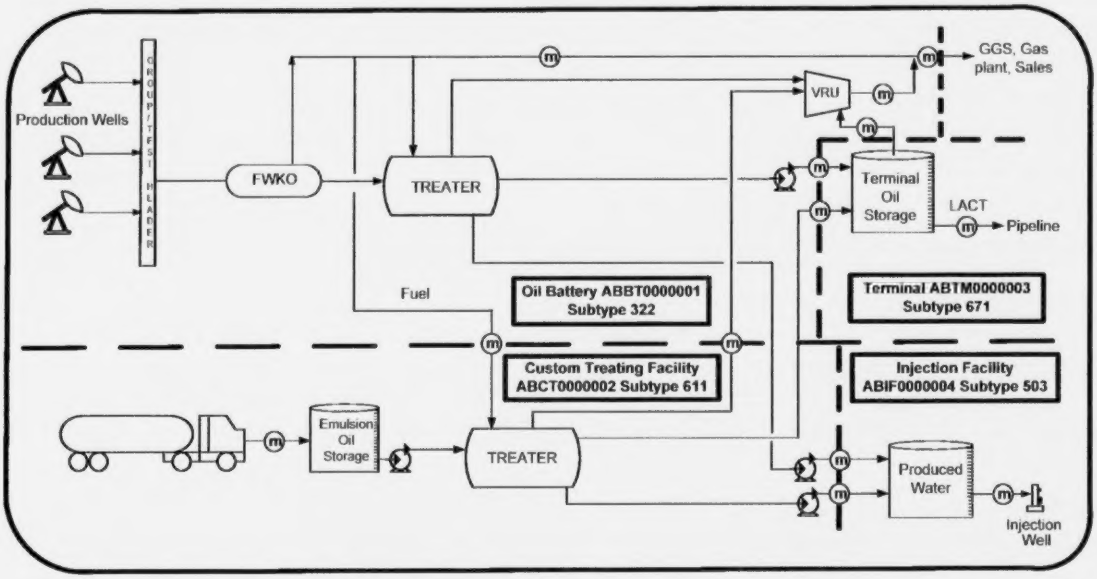
Production Wells
GROUP/TEST HEADER
FWKO
TREATER
Fuel
m
VRU
GGS, Gas plant, Sales
Terminal Oil Storage
LACT
Pipeline
Oil Battery ABBT0000001 Subtype 322
Terminal ABTM0000003 Subtype 671
Custom Treating Facility ABCT0000002 Subtype 611
Injection Facility ABIF0000004 Subtype 503
Emulsion Oil Storage
TREATER
Produced Water
Injection Well

Figure 10.3. Custom treating, oil battery, and terminal schematic – scenario 2

The main difference between the two scenarios is that scenario 1 has dedicated tanks with metering off the tanks, whereas scenario 2 has shared tanks but metering off each treater.

For both scenarios, the transfer of fuel from the proration battery to the custom treating facility provides heat for the custom treater and pressure to help dump the treater to storage tanks. There is also a receipt meter for the gas coming back from the custom treater and terminal to the proration battery.

10.2.2 Custom Treating Facilities

The measurement requirements are the same as for trucking into a conventional oil battery above, but the accounting and reporting must follow the requirements in *Directive 048: Monthly Custom Treating Plant Statement*.

10.2.3 Pipeline Terminals

At the pipeline terminals that receive either pipelined and/or trucked clean oil, the receipt meter or weigh scale measurement is considered to be a custody transfer measurement. That is, there is no proration/allocation from the pipeline disposition volumes to the receipt (REC) volumes that are reported to the PRA. Any measurement beyond this point is considered as downstream operations and not covered in this directive. However, if the downstream pipeline operator allocates to the shippers the imbalance (generally less than 1%) on its pipeline system (according to the contractual requirements) and the allocated volumes are reported to the PRA instead of the measured REC volumes, then the delivery point measurement requirement also applies to the measurement point(s) at the other end of the pipeline. This scenario also applies to Section 10.2.4.

10.2.4 Clean Oil Terminals

Clean oil terminals are those that receive trucked and/or pipelined clean oil only; the receipt meter is considered as a delivery point. That is, there will be proration/allocation from the terminal LACT disposition volumes to the receipt volumes for that month.

Exception

Volumetric allocation of the monthly LACT volumes to the monthly truck receipt volume is not required at a clean oil terminal without ERCB site-specific approvals if all of the following criteria are met:

- The meter factor for each delivery point meter or the weigh scale accuracy verification must not deviate from the prior factor or verification by more than 0.5%.
- Any deviation over 0.5% must be investigated and rectified, and allocation for the previous month(s) disposition volumes to the receipt volumes is required.
- The monthly measurement difference between the receipts and dispositions after including allowances for blending shrinkage, if applicable, and the inventory changes at the clean oil terminal must be less than or equal to 0.5%.

The licensee must revert to allocating monthly pipeline LACT volumes to the receipt volumes if any of the above criteria are not met.

10.2.5 Gas Plants, Gas Batteries, and Gas Gathering Systems

For gas systems receiving trucked liquid, the measurement requirements are the same as for trucking liquid into a conventional oil battery.

10.2.6 Water Injection/Disposal Facilities

For water trucked into an injection or disposal facility, delivery point measurement accuracy is not required. See Section 1.7 for facility accuracy requirements.

10.2.7 Waste Processing Facilities

A waste processing facility handles volumes of waste generated in the upstream petroleum industry. However many ERCB-approved waste facilities have an integrated custom treating facility designated for processing oil/water emulsions extracted from the solids during waste processing. In addition, oil/water emulsions from other batteries are trucked in and measured independently from the waste oil/water emulsions, and both streams are processed through the same treating facilities. The total waste stream disposition to the custom treater (CT) must have emulsion volume and S&W determinations in order to properly allocate the clean oil and water volumes back to the other received emulsions. Therefore, delivery point measurement is required at the receipt point of non-waste truck unloading and at the total waste oil/emulsion delivery point to the CT for further processing, such as in a treater, where it is commingled with other oil/emulsion from other sources.

There are also injection/disposal facilities that receive other liquids, such as waste streams going into subsurface caverns for disposal. Waste liquids for disposal require measurement accuracy similar to disposal of produced water.

See *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry* for the requirements for waste stream measurement, accounting, and reporting.

Integrated Waste Treatment Including Waste Plant (WP), Custom Treating (CT), Water Disposal (IF), and Terminal (TM) Delineation

Integrated oil and water processing and waste facilities are ones with various distinct processing and reporting entities. They are referred to as oilfield waste management facilities (OWMFs). See Figure 10.3.

Any fluids transferred between the different reporting facilities within the integrated site must be measured and reported.

Report fuel gas receipt at the WP and fuel gas usage. See Section 5 of *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities* for more details. No fuel gas transfer or fuel use reporting required at the CT in this case.

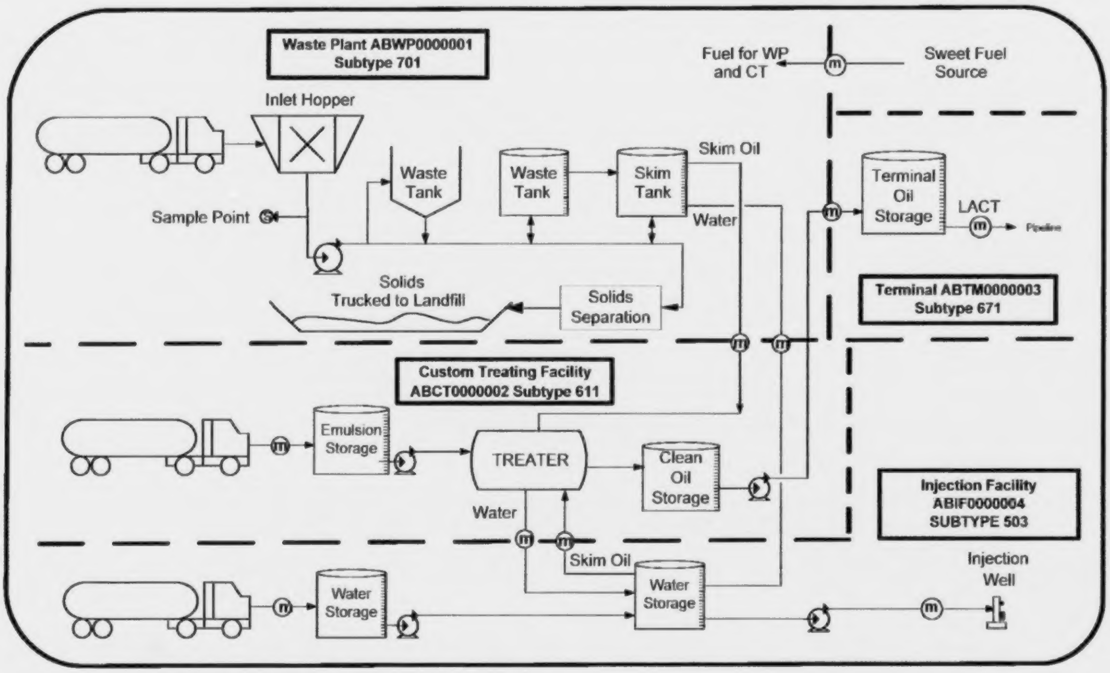
Waste Plant ABWP0000001
Subtype 701
Fuel for WP and CT
Sweet Fuel Source
Inlet Hopper
Skim Oil
Waste Tank
Waste Tank
Skim Tank
Water
Terminal Oil Storage
LACT
Pipeline
Sample Point
Solids Trucked to Landfill
Solids Separation
Terminal ABTM0000003
Subtype 671
Custom Treating Facility
ABCT0000002 Subtype 611
Emulsion Storage
TREATER
Clean Oil Storage
Water
Injection Facility
ABIF0000004
SUBTYPE 503
Skim Oil
Injection Well
Water Storage
Water Storage

Figure 10.3. Integrated waste treatment facility delineation

10.2.8 Heavy Oil and Crude Bitumen Facilities

To meet heavy oil and crude bitumen trucked production delivery point measurement requirements, the licensee must use an appropriate method based on the fluid characteristics, such as viscosity, temperature, and sand content of the load. Generally, delivery point measurement is performed by using weigh scales or tank gauging with sampling to determine the S&W and/or density. Meters are used only when there are minimal or no solids present in the oil/emulsion, similar to trucking into a conventional oil battery.

10.3 Design and Installation of Measurement Systems

Delivery point measurement is required for most trucked fluids delivery/receipt except as mentioned above. The gross volume must be measured through a system consisting of inlet tank gauging, inlet meter, or weigh scale. Gauge boards must not be used for delivery point measurement.

Truck ticket estimates (i.e., volume estimates determined using the truck tank load indicator completed by the trucker or trucking company for bill of lading/transportation of dangerous goods purposes) are not considered as measurement for the purpose of well or facility volume measurement. Therefore, truck ticket estimates must not be used for determining volumes unless the requirements in Section 10.3.4 are met.

See Section 14 for liquid measurement design and installation requirements.

10.3.1 Meters

Turbine meters are typically not suitable for viscous fluids and therefore are not recommended for unloading crude oil.

When metering devices for the purpose of measuring truck delivery/receipt volumes are installed, the following must also be installed:

- sample point
- air eliminator

For some types of meters and applications, a strainer and a back pressure control system are required. (See Figure 14.1.)

Additional requirements for clean oil and pipeline terminals:

1) For mechanical automatic temperature compensators without gravity selection (ATC) or with gravity selection (ATG):

    - For new applications, mechanical ATC and ATG must not be used. All existing ATC and ATG are grandfathered at their existing applications and must not be relocated or reused for other applications.
    - The difference between actual density and compensation density must be less than 40 kg/m^3.
    - Product temperature must be between –10°C and +40°C excluding LPGs.
    - The compensation density (mechanically set density or user-entered density for electronic flow computers) must be a volume weighted average of the expected receipt volumes. When product temperatures exceed 40°C, it may be necessary to reduce the allowable density difference to maintain a 0.5% uncertainty.
    - Temperature compensation devices must be designed for the actual range of operating temperatures observed. If product temperatures exceed 40°C, it may be necessary to reduce the allowable density difference to maintain a 0.5% uncertainty.

10.3.2 Weigh Scales

Weigh scales for the purpose of delivery point measurement must be verified in accordance with Section 2.14. For sampling points and methods, see Section 6.4.2. Systems employing weigh scales must also provide for determination of density of oil and water in accordance with one of the following:

1) API MPMS, Chapter 9: Density Determination Using Hydrometer,
2) precision laboratory method – ASTM method, or
3) on-line densitometer (Coriolis, nuclear device, etc.).

To maintain an uncertainty of 0.5% or less, the net weight of the payload must not be less than 40% of the gross vehicle weight and the net weight must not be less than 6500 kg. An exemption from this requirement is granted only during seasonal road ban periods when reduced truck loads are mandated by weight restrictions.

10.3.3 Exceptions

10.3.3.1 Truck-Mounted Level Gauges and Truck-Mounted Meters

Truck gauge level indicators and truck-mounted meters are considered to have met the requirement for low-accuracy measurement with an overall uncertainty of ±1% or less if the following criteria are met. These units can be used for trucked-in delivery point measurement to proration oil batteries if all of the following requirements are met:

- the battery receives not more than 100 m^3 of trucked-in oil per day;
- the maximum percentage of trucked-in oil to any battery is 10% of the monthly total battery oil production volume;
- the gauges or meters are verified/proved annually and if not within ±1% accuracy they are repaired and recalibrated/reproved;
- the product temperature is determined to within 1°C (see Section 10.3.2, item 2); and
- the truck gauge levels or meters are initially set by calibrating to a master meter or provers with a demonstrated uncertainty of not more than 0.2%.

Additional criteria for truck-mounted level gauges:

- the stated depth of liquid is within 12.7 mm of a known gauge level marker if used;
- the depth of liquid is determined while the tank trailer is level to within 150 mm over its length; and
- the minimum load on the trailer is more than 65% of full load.

10.3.3.2 Truck Tickets and Lease Tank Gauging

Truck ticket volumes uncorrected for temperature are not acceptable for delivery point measurement of trucked liquid. If the fluid transfers are between unitized or common equity facilities with common royalty, then the temperature correction estimates may be used. The truck ticket must be based on a low-accuracy measurement requirement with an overall uncertainty of ±1% or less of trucked liquid, such as lease tank gauging at the battery sending the liquid production or truck-mounted meter, for determining inlet volumes at a proration battery if certain situations exist. The S&W% and corrected opening and closing readings must be on the ticket or available on a summary sheet for ERCB audit purposes. An individual truck load should be recorded on its own ticket.

The ERCB may accept low-accuracy measurement with an overall uncertainty of ±1% or less for trucked liquid production at a proration battery if

- trucked production is temporary, pending battery consolidation within one year or less;
- individual well oil volumes being trucked are less than 2.0 m^3/day (see Section 10.3.5);
- the crude oil volume receipt (net of water) is 5% or less of the total receiving battery oil production; and
- truck-mounted meters used for low-accuracy measurement with an overall uncertainty of ±1% or less are proved in accordance with the requirements in Section 2.

10.3.4 Load Fluids

Load fluids at a minimum must be measured using devices that meet the requirement for low-accuracy measurement with an overall uncertainty of ±1% either at the source (loading) location or at the delivery point.

Reporting of load fluid on the PRA is limited to oil-based and/or water-based fluid(s) injected during preproduction well stimulation or postproduction activities. Only the load fluid product codes OIL, COND, or WATER can be reported. Well drilling fluids must not be reported on the PRA as load fluids.

Load fluids are to be reported at the well level except when in an SE Alberta shallow gas battery, since there is no requirement to measure and report water production at this type of well. The load fluid reporting then can be done at the battery level.

See the *Directive 007: Volumetric and Infrastructure Requirements* (December 2007) on-line supplement Appendix 8 for more reporting procedures.

10.3.5 Split Loads

A split load is defined as existing when a truck takes on partial loads from more than one well or battery in a single trip or when load oil is delivered to more than one receipt point or wells.

Allowed	- Single-well oil battery delivering to other facilities
	- Gas wells with condensate-water tanks and production less than 2.0 m^3 of total liquids per day
	- Blending of heavy oil and condensate
	- Load oil for well servicing only; load up from a single source only
Not allowed	- Multiwell batteries delivering to other facilities other than load oil
	- Gas wells with production greater than 2.0 m^3 of total liquids per day

Requirements Densities must be "similar" (within 40 kg/m^3). If they are not, blending tables are required to calculate shrinkage. The shrinkage volume is to be prorated back to each battery on a volumetric basis.

Measurement Volume from each well or facility must be measured at the time of loading onto the truck (or off loading from the truck for load oil) by one of the methods below:

1) gauging the battery lease tank;
2) gauging the truck tank (not allowed for density difference over 40 kg/m^3 for any oils or emulsions); or
3) truck-mounted meter/gauge that meets low-accuracy measurement and is proved at least annually.

Calibrated gauge tables are required for methods (1) and (2) above.

Sampling Fluid from each single-well oil battery must be sampled to determine the S&W and the oil/water volumes. The truck driver is to collect the samples by taking at least three well-spaced grab samples during the loading period (see Section 14.6).

For load oil, the S&W must be determined at the loading source.

Records The truck tickets must show the individual load volumes, as well as the total volume at delivery (receipt) point, supported by opening and closing gauge or meter readings.

Accounting For battery emulsions, the total load is to be measured and sampled at the receiving location and prorated to each of the wells based on the measured loading volumes and S&W from each of the wells.

For load oil, the initial volume must be measured at the loading source and prorated to each delivery point based on the measured volume delivered to each well.

10.4 Sampling and Analysis

For trucked-in hydrocarbons and emulsions receipt/delivery, a truck thief sampler or a proportional sampler may be used to obtain a sample from the truck tank (see Section 14.6). In some cases spot (grab) samples may be used to obtain the sample from the off-load/load line. Automatic sampling methods are preferred; however, manual or tank sampling systems may also be allowed, as discussed below.

The frequency of sampling or readings must be sufficient to ensure that a representative sample of the entire truck volume is obtained. Consideration must be given to both conditioning the flow stream and locating a probe or sampler. Flow conditioning to ensure turbulent mixing can be achieved through velocity control, piping configurations, or introduction of a mixing element upstream of the sample point. A sample probe is required for truck delivery point sampling unless there is an in-line product analyzer or the sampling is incorporated as part of the measurement system. A mid-pipe probe location should be used for accurate sampling. (Also see Section 8.2.1.)

The licensee must choose the sampling methodology based on emulsion characteristics, stratification, and S&W consistency of each load to obtain a representative sample. API MPMS, Chapter 8.1, Section 8, provides further information on manual sampling procedures.

10.4.1 Automatic Sampling

Automatic sampling is typically conducted through the use of proportional samplers. If automatic sampling procedures are used, a manual procedure should also be in place for use when the automatic system is out of service or for intermittent verification of the automatic system reading. For more information, API MPMS, Chapter 8.2, Sections 7 to 15, provide further details on flow conditioning, probe location, and sampling frequency.

Other requirements for automatic sampling:

- Containers made of suitable material for handling and storage of the sample must be used. Container lids must be vapour tight.
- All sample containers must be cleaned and dried prior to collection of the next sample.
- Sample containers must allow adequate room for expansion and content mixing, taking into consideration the temperature of the liquid at the time of filling.
- The sample containers must be housed in a secured enclosure to prevent any tampering with the sample.
- Sample lines must be as short as practical and sloped downward to reduce the possibility of plugging up the sample line.

10.4.2 Manual Spot (Grab) Sampling

Manual spot (grab) sampling may be acceptable in situations involving a tight emulsion with less than 0.5% S&W in the truck by taking three well-spaced grab samples during the unloading period (see Section 14.6). Grab samples are not acceptable when there is stratification of S&W within the truck.

The use of manual sampling techniques, such as truck tank thieving (full height or intermittent), may also be acceptable. However, in the presence of stratification, one unit of height at the bottom of the truck tank represents a significantly lesser volume than the same unit of height at the midpoint of the truck tank because of the shape of the tank. The resulting S&W from a full-height core thief therefore may not be representative of the entire load. Then multiple grab samples are to be used.

Lease tank thieving is subject to similar stratification limitations (excluding the non-uniformity of the tank). These concerns can be reduced by locating any water-emulsion interface and obtaining bottom, middle, and top samples of the emulsion to determine the average water cut of the emulsion. However, lease tank thieving requires dedicated tankage for each load received or delivered to avoid mixing of product between deliveries.

Visual estimates or estimates based on changing off-load pump speeds must not be used for free water volume determination.

10.4.3 S&W Determination

The licensee must select the most appropriate method for determining the S&W. See Section 14.8 and Appendix 4.

10.4.4 Density Determination

Truck load sample density determination at 15°C must be conducted at least annually or more frequently if there are changes in the reservoir conditions. Density of the load may be determined by one of the following methods:

1) Truck load samples may be collected from the receiving point and sent to an independent laboratory for analysis to determine density of the hydrocarbon phase and the water phase (if required). The density found in this analysis must be applied to all hydrocarbon liquids coming from the specific facility.
2) Truck load samples or samples from automatic samplers may be tested for density as outlined in Section 14.6.

In applications where the truck volumes have an S&W greater than 1%, density determination at 15°C of an emulsion sample is difficult, as there are two different thermal corrections to be applied, one for the water and one for the oil.

There are two options available:

- The first is to determine the sample density using a precision densitometer that has its measuring cell at 15°C. No further corrections are required.
- The second is to separately predetermine the density at 15°C of the water and the oil. When using this option, the emulsion density is calculated by applying the S&W cut to the density of each component. The calculation is

$$\rho_{emulsion} = (\rho_{oil} \times (100 - \%S \& W)) + (\rho_{water} \times \%S \& W)$$

where

$\rho_{emulsion}$ is the calculated density of the emulsion at 15°C

ρ_{oil} is the density of the oil portion at 15°C

ρ_{water} is the density of the water portion at 15°C

10.5 Volume Determination

10.5.1 Tank Gauging

Tank gauging procedures are detailed in Section 14.7. The starting and closing levels measured are then converted to volume through the use of gauge tables (supplied by the tank manufacturer), which have been calculated using measurements of the tank. The difference between the closing and opening volumes is the measured volume. If the tank is used for delivery point measurement, the temperature and density of the tank contents must be taken in order to correct the indicated volume to standard conditions before determining the volume difference.

10.5.2 Weigh Scales

The procedure for determining the volume of liquid on a truck using a scale is to weigh the truck before and after loading or unloading and determine the difference to obtain the net weight. The entire load must be weighed at a time—i.e., split weighing, whereby the truck is weighed after unloading a portion of its load to obtain the weight of the unloaded portion, is not permitted unless it is used in cold heavy oil measurement.

To determine the density of the load, an on-line densitometer maybe used or a representative sample must be obtained and the density and temperature measured with a hydrometer and thermometer respectively. The observed density must be corrected to 15°C.

The net weight determined during the weighing process divided by the sample density at 15°C results in the net volume of the load prior to deductions for S&W.

10.5.3 Meters

Metered volumes must be determined in accordance with Section 14.

11 Acid Gas and Sulphur Measurement

This section presents the base requirements and exceptions for acid gas and sulphur measurements at processing plants and injection facilities in the upstream oil and gas industry that are used in determining volumes for reporting to the ERCB. *S-30 Monthly Gas Processing Plant Sulphur Balance Report* requirements are also included, with instructions provided in Section 11.6.

In a gas processing plant where sour gas is processed, most of the acidic portion of the gas must be removed from the gas stream (sweetening) in order to produce a saleable pipeline-quality gas product. However, in the process of removing the acidic portion of the sour gas, acid gas, which consists mainly of H_2S and CO_2, is generated and must be disposed of in an environmentally and economically acceptable way, such as by elemental sulphur production, acid gas injection, or acid gas flaring.

11.1 General Requirements

The sour gas plant inlet and acid gas streams must be measured and reported. The inlet sour gas stream volume including GEV of condensate, sour gas in solution in water, the sulphur disposition tonnage, and the sulphur balance must be reported on a monthly basis on the S-30 report if the plant is approved with a sulphur inlet of more than 1 tonne per day (t/d) to the ERCB. See Table 11.1 for the monthly S-30 sulphur balance requirement. For sour gas plants with less than 1 t/d of approved sulphur inlet, the S-30 report must be submitted to Alberta Environment at its required timing, with the exception of grandfathered plants that would still be required to submit S-30 reports to the ERCB until December 31, 2016. For plants that are licensed as "sweet" but use a sweetening process to strip out excess CO_2, the reporting of the acid gas (CO_2) volume must be the same as sour plants under 1 t/d.

Table 11.1. Monthly S-30 Sulphur Balance Requirement

Monthly average actual sulphur inlet (t/d)	Sulphur balance %
< 1	20%
≥ 1	5%

In accordance with *Interim Directive (ID) 2001-03: Sulphur Recovery Guidelines for the Province of Alberta*, other upstream oil and gas facilities with sulphur emissions greater than 1 t/d that are not required to submit S-30 reports must maintain daily sulphur balance records and calendar quarter-year recovery calculations. These records must be available for inspection or audit at the request of the ERCB.

The acid gas from the sweetening process is generally saturated with water vapour (wet). This water vapour portion must be subtracted from the saturated acid gas to obtain the dry volume without water vapour. (See Section 11.2.)

11.2 Acid Gas Measurement

The quantity of acid gas going to sulphur plants, to compression and injection, or to flaring is generally measured at a low pressure of 50 to 110 kPag; therefore, the orifice meter, or any other meter, must be appropriately sized and well maintained to achieve accurate measurement.

Acid gas is saturated with water vapour, which represents a significant portion of the total gas measured. The amount of water vapour varies significantly with the temperature of the reflux drum. Therefore, the acid gas meter must have continuous temperature correction (see

Section 4.3) to calculate the correct acid gas volume (see below). The gas density must also include the water content, and the meter coefficient must include a factor to exclude the water vapour content of the gas in the final volume computation for reporting purposes. The accuracy of the gas relative density factor and water content determination must be periodically verified to ensure that acid gas measurement uncertainty is within tolerance.

11.2.1 Determining Acid Gas on a Dry Basis

For ideal gases, the total vapour pressure of a system containing several components is the sum of the vapour pressure of the individual components at the temperature of the system.

The component's vapour pressure percentage of the total pressure of a system is equal to the volume percentage of that component in the system. The reflux drum is the vessel in which the acid gas separates from the sweetening solution. The amount of water vapour in the acid gas leaving the reflux drum is a function of the temperature and the absolute pressure in the reflux drum.

Calculating Acid Gas Flow Rate

The recommended calculation method for the acid gas flow rate is as follows:[1]

Step 1: Determine the percentage of water vapour in the acid gas on the basis of the ratio of vapour pressure of water to total pressure in the reflux drum at the reflux drum temperature.

Step 2: Convert the acid gas composition from dry basis to wet basis at reflux drum pressure and temperature, and determine the acid gas relative density and compressibility factor on a wet basis at meter pressure and temperature.

Step 3: Calculate the acid gas and water vapour flow rate corrected from actual flowing pressure and temperature to standard conditions of 101.325 kPa(a) and 15°C.

Step 4: The volume calculated in step 3 contains water vapour in the percentage determined in step 1 and must be converted to dry basis volume for reporting purposes. A **correction factor (CF)** has to be applied to correct the acid gas flow from a wet to a dry basis.

CF = (100.00 – % H_2O in acid gas)/100

Dry acid gas flow rate = CF x flow rate calculated in Step 3

The H_2S content of the acid gas is the dry basis acid gas flow times the % H_2S/100 in the acid gas on a dry basis.

Calculating Vapour Pressure of Water

The formula for determining the vapour pressure of water[2] is

$\log P = A - B/(C + T)$

where P = water vapour pressure in mm of mercury
A = 8.10765
B = 1750.280
C = 235
T = temperature of acid gas in reflux drum (°C)

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[1] Wichert, E., "Water content affects low pressure, acid-gas metering," *Oil & Gas Journal*, January 2, 2006, pp. 44–46.

[2] The vapour pressure of water at a certain temperature can also be obtained from the GPSA *Engineering Data Book*, SI Units version, 12th edition, 2004 or subsequent versions, Figures 24–36.

The direct formula for determining the vapour pressure of water in kPa(a) is thus

$P_{H2O} = 0.13332 * 10^{(8.10765 - 1750.280/(235 + T))}$

where P_{H2O} = water vapour pressure in kPa(a) at T°C

% H_2O in the acid gas = 100 % * $P_{H2O}/(P_{RD} + P_{atm})$

where P_{RD} = reflux drum pressure, kPag

P_{atm} = atmospheric pressure, kPa(a)

This method for estimating the water vapour content of acid gas replaces the method contained in Section B-2 of *Directive 046: Production Audit Handbook*. There is no grandfathering for using the methodology in *Directive 046*. Noncompliance will not be assessed until after May 1, 2009, to allow industry sufficient time to implement the changeover of methodology.

Converting Acid Gas Calculation from Dry to Wet Basis

An example acid gas conversion calculation from dry to wet basis with the meter installed upstream of the back-pressure regulator of the reflux drum is provided below:

A. Reflux drum data

Reflux drum temperature = 40°C
Reflux drum pressure = 70 kPag
Atmospheric pressure = 95.0 kPa(a)

If the meter is installed upstream of the back-pressure regulator of the reflux drum, the upstream pressure and the temperature of the meter run may be used as the reflux drum pressure and temperature.

B. Acid gas components on a dry basis from acid gas analysis:

H_2S = 65%; CO_2 = 33.5%; C_1 = 1.2%; C_2 = 0.3%

C. Calculate the percentage of components, including water vapour, on a wet basis:

Percentage of water vapour = (100 % * Vapour pressure of water at 40°C) / (Reflux drum gauge pressure + atmospheric pressure)

$P_{H2O} = 0.13332 \times 10^{(8.10765 - 1750.280/(235 + 40))}$

= 7.377 kPa(a)

(Vapour pressure of water at 40°C is 7.384 kPa(a), from the Saturated Steam Table in the Thermodynamics section of the GPSA *SI Engineering Data Book*, Figures 24-36.)

Percentage of water vapour = 7.377/(70 + 95) * 100% = 4.47%

Enter into column 2 (see the following table) and normalize.

Calculation of relative density (RD) on wet basis

Comp.	Col. 1 Dry basis (%)	Col. 2 Wet basis (%)	Col. 3 Molar mass (kg/kmol)[1]	Col. 4 (Col. 1 * Col. 3) /100	Col. 5 (Col. 2 * Col. 3) /100
H_2S	65.00	62.09	34.082	22.153	21.162
CO_2	33.50	32.00	44.010	14.743	14.083
C_1	1.20	1.15	16.042	0.193	0.184
C_2	0.30	0.29	30.069	0.090	0.087
H_2O	0.00	4.47	18.0153	0.000	0.805
Total	100.00	100.00		37.179	36.321

[1] Molar mass of air = 28.9586 kg/kmol (GPSA *Engineering Data Book*, 2004 or later editions, Figure 23-2, or GPA-2145).

From column 4, ideal gas RD, dry basis = 37.179/28.9586 = 1.284.

From column 5, RD wet basis = 36.321/28.9586 = 1.254 (this RD is to be used in the flow calculation for acid gas volumes).

11.2.1.1 Difference Between the Acid Gas Volume on a Wet Basis and on a Dry Basis

An example calculation is presented to show the difference in the results of the acid gas flow rate and the sulphur content of acid gas using dry versus wet basis metering. The example data for the meter run and assumed conditions are as follows:

Orifice meter diameter:	154.051 mm
Orifice plate diameter:	76.200 mm
Meter upstream pressure:	70.00 kPag
Differential pressure:	10.00 kPa
Meter temperature:	40°C
Atmospheric pressure:	95.0 kPa
Acid gas composition:	as per above table

Results with AGA #3 1992 or later method:

- Flow rate, dry basis without accounting for moisture content = 33.126 10^3 m^3/d
- Sulphur content = 33.126 x 65/100 * 1.35592 = 29.20 t/d
- Flow rate, wet basis = 33.499 10^3 m^3/d, containing 4.47 vol % H_2O
- Flow rate, wet basis converted to dry basis = 33.499 * (100 – 4.47)/100
  = 32.002 10^3 m^3/d dry acid gas equivalent

This volume, 32.0 10^3 m^3, is to be reported as "Acid Gas" on the monthly volumetric submission.

An example for percentage difference in acid gas volume between dry and wet basis:

- Percentage difference in flow rate = (33.126 – 32.002) * 100 %/32.002 = 3.51%
- Sulphur content = 32.002 * 65/100 * 1.35592 = 28.21 t/d
- Difference in calculated sulphur balance between dry and wet basis metering = 29.20 – 28.21 = 0.99 t/d
- Percentage difference = 0.99 x 100/28.21 = 3.51%

Thus, if the moisture content in the metering of the acid gas in this example were ignored (dry basis taken as wet basis), the reported acid gas flow and sulphur content in the acid gas leaving the reflux drum would be 3.51% higher than the correct value.

This method of estimating the water vapour content is valid when the gas is in contact with water in a low-pressure vessel, such as in the reflux drum. The method does not apply to low-pressure gas, such as in a flare line, when the flared gas originates from a high-pressure vessel.

The table below summarizes the above figures and also provides the results that are obtained by the 1985 AGA # 3 Report method, using Wichert-Aziz (W-A) compressibility factors.

	AGA #3, post-1992		AGA #3, 1985, W-A Z factors*	
Item	**Dry basis**	**Wet basis**	**Dry basis**	**Wet basis**
Z factor at St'd P and T	0.992 848	0.991 999	0.993 037	0.992 788
Z factor at Meter P,T	0.991 002	0.990 030	0.991 007	0.990 674
Flow rate, $10^3 m^3/d$	33.126	33.499	33.096	33.481
Corrected to dry gas	-	32.002	-	31.984
% difference	-	3.51	-	3.48
Sulphur flow, t/d	29.20	28.21	29.17	28.19
% difference, t/d		3.51		3.48

*Z factors by Wichert-Aziz method, including water content in wet gas.

11.2.1.2 Calculation Method of Water Content if Meter Located Downstream of Back-Pressure Valve of Reflux Drum

The water content in the acid gas is a function of the pressure and temperature of the reflux drum. If the acid gas meter is located downstream of the back-pressure regulator of the reflux drum, both the pressure and the temperature of the meter will be somewhat lower than the pressure and temperature of the reflux drum. Under these conditions, it is still necessary to determine the water vapour content of the acid gas stream at the reflux drum pressure and temperature, as shown above, to correctly calculate the acid gas flow rate.

The reflux drum pressure must be recorded for the correct calculation of the water vapour content of the acid gas. The reflux drum temperature should also be used to estimate the water content. However, since the flow data from the meter include the temperature at the meter run, the reflux drum temperature can be estimated on the basis of the meter temperature, as follows:

$$T = T_m + 2.28 - 2.28 * P_2/(P_{RD} + P_{atm})$$

where P_2 = the downstream meter tap pressure, kPa(a)

T_m = temperature downstream of the orifice plate

Having estimated the temperature at the reflux drum from the temperature downstream of the orifice plate, the vapour pressure of the water can be calculated as above. The percentage of water vapour in the acid gas can then be determined using the reflux drum pressure, and the same procedure as outlined in the above example can be used to calculate the acid gas flow rate.

11.2.1.3 Effect of Compression and Cooling of Acid Gas

In the situation of acid gas compression and injection, the acid gas flow rate may in some instances be metered after one or more stages of compression and cooling (see Section 11.4.4.3). This will remove a sufficient amount of water so that the remaining water vapour in the compressed and cooled acid gas will have little effect on the acid gas metering. In such a situation, it is not necessary to include the effect of water vapour in the metering of the acid gas.

11.3 Sulphur Measurement and Pit Volume Determination

11.3.1 Sulphur Pit Volume/Tonnage Determination

When pit gauging is used to determine a liquid sulphur volume, the gauging procedures must be conducted in accordance with the following:

- The operator must ensure that the gauge/strapping table used to convert the gauge level to a liquid volume is specific for the pit being gauged.
- Pit gauging should be used for inventory determination only and must not be used for delivery point measurement.
- All dip sticks and electronic level devices must have a minimum resolution of 6 mm.
- It is acceptable to have one reading per determination.
- The sulphur density at pit temperature is obtained from Figure 11.1.[3]

The general formula for determining the produced sulphur tonnage is as follows:

Sulphur tonnage = Gauge reading x CF x Sulphur density

where CF = Pit gauge/strapping table conversion factor

11.3.2 Sulphur Measurement

For sulphur sales/delivery point measurement using meters, see Section 6.3.1.1. These meters must be kept at a temperature so that the molten sulphur will not solidify when there is no flow.

For sulphur sales/delivery point measurement using a weigh scale, see Section 2.13.

For daily sulphur production measurement using pit level gauging, two pits are required, one for production and the other for withdrawal using level measurement. The daily sulphur production tonnage should be adjusted by the total monthly disposition at the end of the month (see Section 11.3.2.1).

11.3.2.1 Exceptions

For daily sulphur production volume determination, if there is only one pit in place in an existing plant and sulphur is being withdrawn without measurement, the operator may use the measured acid gas volume on a dry basis, provided that there is a continuous acid gas sampling device, such as a gas chromatograph, to calculate the sulphur tonnage entering the sulphur plant. The daily sulphur production can then be calculated using the following formula:

Estimated daily sulphur production (t) = Daily acid gas inlet (t) – Daily incineration (t) –
Daily flared (t) – Others if applicable (t)

The estimated daily sulphur production tonnage must be adjusted by the total monthly disposition at the end of the month by calculating a proration factor and applying that to all estimated daily production tonnage:

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[3] Tullen, W. N., *The Sulphur Data Book*, New York: McGraw-Hill Book Company, Inc., 1954, p. 17.

Sulphur proration factor (S_{pf}) = Total monthly sulphur disposition tonnage (including inventory changes) ÷ Total estimated daily sulphur production tonnage

Actual daily sulphur production (t) = Estimated daily sulphur production (t) × S_{pf}

The "actual daily sulphur production" is the daily production tonnage to be reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report.

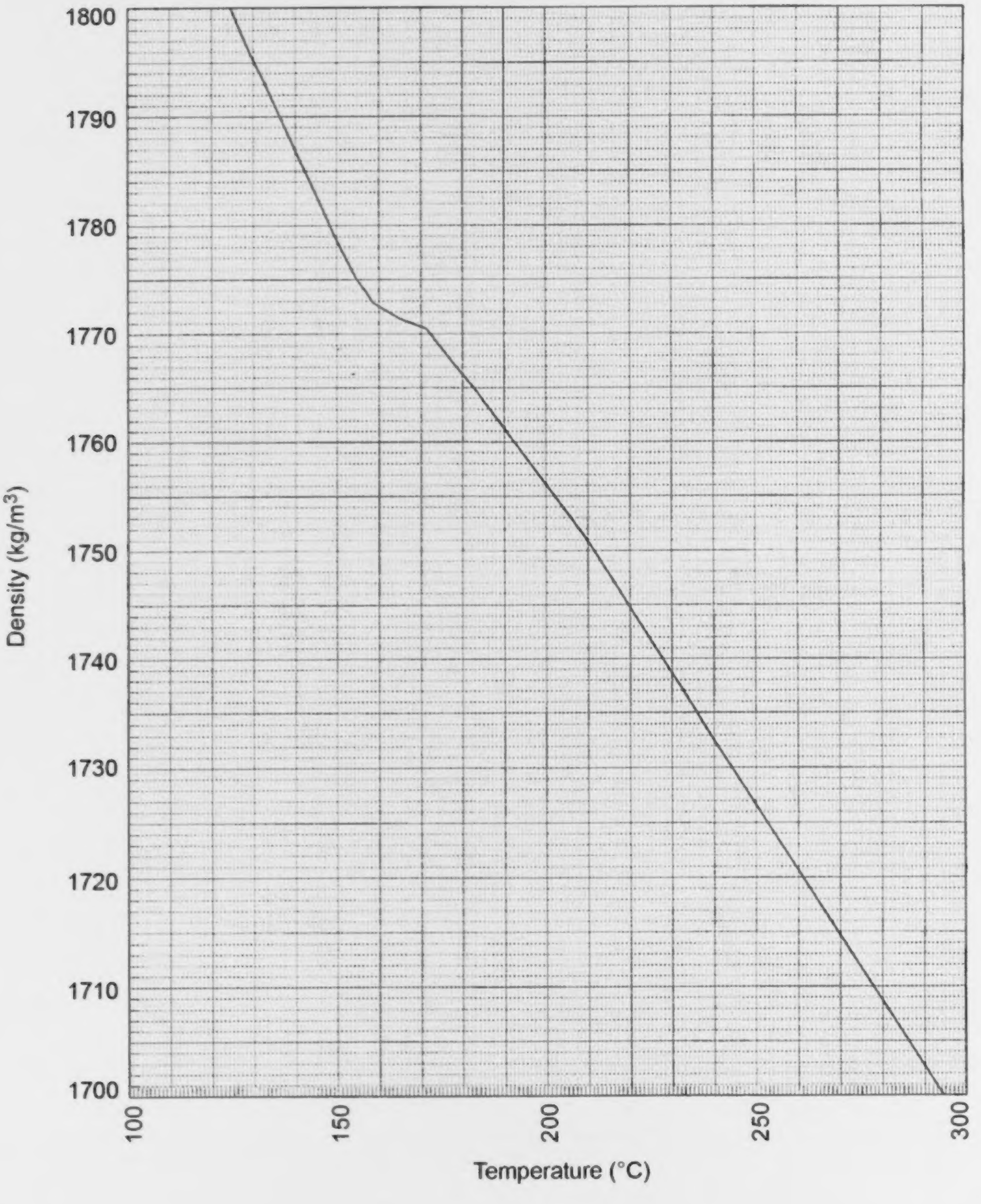


Figure 11.1. Liquid sulphur density vs. temperature

11.4 Sulphur Balance Calculation for Sour Gas Processing Plants

When sour gas is produced to a sour gas treating plant, it always enters the plant through a plant inlet separator. A liquid water phase is usually present with the sour gas, and in many instances a liquid hydrocarbon phase can also be produced into the separator with the gas and water. In such situations, all three phases will contain some H_2S in different proportions.

All of the H_2S entering the plant in the different fluids will also exit the plant by one means or another. The balance is an important part of checking to ensure that all streams are accounted for and reported. The S-30 reports a monthly balance between the accounting of the mass of sulphur entering and leaving the plant for sour gas plants with an approved sulphur inlet rate greater than 1 t/d. To achieve this objective, certain minimum measurements of concentrations and flow volumes must be made by the plant operator. This section provides the minimum requirements to achieve the desired goal.

If a monthly balance in Table 11.1 in Section 11.1 cannot be achieved on a regular basis, the operator must implement appropriate measures to ensure that the required plant-wide balance is achieved. Appropriate measures include, but are not limited to,

- improving the acid gas, inlet gas, flare, and sulphur measurement systems;
- installing a continuous gas analyzer on the gas stream of the plant inlet separator and/or on the outlet gas stream of the reflux drum for acid gas flaring plants;
- installing a proportional sampler on the gas stream of the plant inlet separator; and
- improving the methodology for determining sulphur content in inlet condensate and water.

11.4.1 Overview of Plant Inlet and Outlet Points for H_2S

Figure 11.2 illustrates the paths by which H_2S enters the sour gas plant and by which method it can exit from the plant.

The H_2S entering the plant in the gas, condensate, and water has to be accounted for on the S-30 report in terms of tonnes of elemental sulphur. Since the flow volumes of the three types of fluid streams out of the inlet separator are required to be measured, it becomes a simple task to account for the amount of H_2S entering the plant by determining the H_2S concentration in each stream.

11.4.2 Determining H_2S Contents

11.4.2.1 Determining H_2S in Sour Gas

See Section 8.2 for the determination of H_2S concentration in the inlet gas stream.

11.4.2.2 Determining the Concentration of H_2S in Condensate

Condensate associated with sour gas will contain some H_2S. The physical relationship between the concentration of H_2S in the gas and in the condensate depends on the composition of the gas and the condensate and the pressure and temperature in the plant inlet separator. The concentration of the H_2S in the condensate is usually determined in a laboratory on condensate samples obtained from the inlet separator.

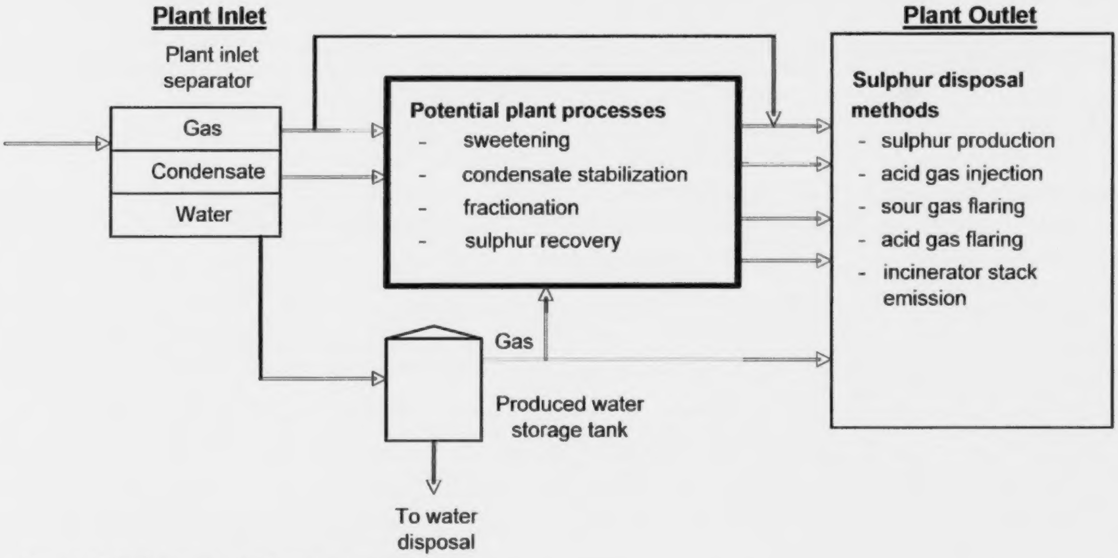

Plant Inlet
Plant inlet separator
Gas
Condensate
Water
Potential plant processes
- sweetening
- condensate stabilization
- fractionation
- sulphur recovery
Plant Outlet
Sulphur disposal methods
- sulphur production
- acid gas injection
- sour gas flaring
- acid gas flaring
- incinerator stack emission
Gas
Produced water storage tank
To water disposal

Figure 11.2. Sour gas plant process overview

As long as the gas and condensate entering a sour plant originate from a single pool, the H_2S concentration in the condensate will likely remain quite stable at the sampled conditions of pressure and temperature. Minor changes in pressure and temperature of the separator will only have a slight influence on the composition of the condensate. If major changes in pressure occur, such as due to installation of plant inlet compression and the resultant lowering of the inlet pressure, new samples must be taken and analyzed.

If the production to the plant occurs from two or more pools with different reservoir fluid compositions, the composition of the condensate will vary. In such cases, a vapour/liquid equilibrium correlation between the mole fraction of H_2S in the sour gas and the condensate can be used to estimate the mole fraction of H_2S in the condensate based on compositional analysis, computer process simulation, or stabilizer overhead volume and % H_2S to ensure acceptable accuracy for the S-30 report balance.

11.4.2.3 Determining Concentration of H_2S in Inlet Separator Water

The concentration of H_2S dissolved in the water that enters the plant inlet separator is a function of the separator pressure and temperature, as well as the concentration of H_2S in the sour separator gas. The amount of H_2S dissolved in the water can be predicted quite readily with correlations based on compositional analysis or computer process simulation.

Water can be metered ahead of the liquid level control valve on the water outlet line from the separator, or it can be gauged in a low-pressure produced water storage tank. The vapours from the tank are usually swept from the tank to flare with sweet gas. Some plants producing large amounts of sour water have installed a vapour recovery system, by which the tank vapours are conserved and treated in the processing plant.

If the total estimated sulphur content dissolved as H_2S in the sour water is less than 0.05 t/d (50 kg/d), the amount may be ignored in the balance determination.

It is recognized that a portion of the H_2S in the water of the plant inlet separator will remain in the water when the water is disposed of in a disposal well. This amount of H_2S is small and will depend on the water temperature in the produced water storage tank at atmospheric pressure, the amount of agitation in the water, and whether sweet gas is used for sweeping the vapours from the tank to flare. The small amount of H_2S remaining in the water is difficult to estimate and therefore need not be included in the disposal accounting.

11.4.3 Calculation Procedure for Estimating the Plant Sulphur Inlet Mass per Day

1) The following streams must be accurately metered:
   a) sour gas out of the separator, Q, 10^3 m^3/d,
   b) sour condensate out of the separator, converted to gas equivalent volume, 10^3 m^3/d, and
   c) sour water out of the separator or into the storage tank, m^3/d, if required.

2) The sulphur content in the sour gas out of the separator can be calculated:

   Sulphur equivalent in sour gas, t/d = (Q, $10^3 m^3/d$) (y) (1.35592)

   where y is the mole fraction of H_2S.

3) The condensate must be sampled and analyzed semiannually as a minimum frequency, in accordance with Section 8. When there are continuous gas analyzers and the H_2S content in the gas stream changes, the sulphur content in the condensate out of the separator can be calculated on the basis of the mole fraction of H_2S in the separator gas. The formula below should be used. Any alternative methods used must be supported by documentation that it is equivalent to the above method and made available to the ERCB upon request.

   $x = y/K$

   where: x = mole fraction of H_2S in the separator condensate

   y = mole fraction of H_2S in the sour gas in the plant inlet separator

   $K = A + (B-A)(T/66)^{1.2}$

   $A = -0.7034\,(LOG_{10}(P))^3 + 9.1962\,(LOG_{10}(P))^2 - 39.58\,LOG_{10}(P) + 56.695$

   $B = -3.9694\,(LOG_{10}(P))^3 + 46.021(LOG_{10}(P))^2 - 178.95\,LOG_{10}(P) + 234.35$

   T = temperature of the sour gas in the plant inlet separator or metering temperature, °C

   P = pressure of the plant inlet separator, kPa(a)

   Sulphur equivalent in condensate, t/d = (Gas equiv. of condensate, $10^3 m^3/d$) (x) (1.35592)

   The range of applicability of the above method for determining x, the mole fraction H_2S in condensate, is between 700 to 9000 kPa(a) and 0 to 80°C.

4) The amount of H_2S dissolved in the water, z (mole fraction), in the plant inlet separator can be estimated by the following formula:[4]

   $z = y/(4.53 - 7494.6/P + 758.4\,(1.8\,T + 32)/P + 4.65\,y)$

   where all terms are as defined above.

   Sulphur equivalent in water, t/d, = (1.31) (water production, m^3/d) (z) (1.35592)

---

[4] Froning, H. R. Jacoby, R. H., and Richards, W. L., "New K-Data Show Value of Water Wash," *Hydrocarbon and Petroleum Refiner*, April 1964, pp. 125–130.

The sum of the results of points 2, 3, and 4 for each sour gas inlet separator is the total sulphur inlet to the plant in t/d.

11.4.4 Calculation Procedure for Estimating Plant Sulphur Outlet Mass per Day

There are basically three different sulphur disposal schemes approved by the ERCB:

- sulphur recovery,
- acid gas flaring, and
- acid gas compression and injection.

Each of these schemes is treated separately as far as collecting the disposition data for the S-30 report is concerned. The plant inlet data are collected identically for the above different sulphur disposal schemes.

Potential sulphur disposal methods from sour gas plants are

- sulphur recovery,
- sour gas flaring or incineration,
- acid gas flaring or incineration,
- sulphur plant incinerator stack emissions, and
- sour gas flaring or incineration from the produced water storage tank (> 0.05 t/d).

The disposal of the sulphur by any of these methods must be accounted for. This requires measurement of flow rates and knowledge of concentrations of H_2S in the gas streams.

An important feature of the sulphur balance on the outlet side is the determination of the H_2S content of the acid gas out of the reflux drum. This gas stream is fully saturated with water vapour at the operating pressure and temperature of the reflux drum. Depending on what method is used in the determination of the H_2S content, the results could be on a dry basis or a wet basis. The operator must determine on which basis the analysis is determined.

The water content of the acid gas out of the reflux drum can be estimated by the procedure in Section 11.2.1.

Any H_2S determination and any complete analysis of the acid gas stream from the reflux drum presented on a dry basis must be normalized to a wet basis by the inclusion of the water vapour mole fraction. If the H_2S content in the acid gas is determined on a wet basis, the water vapour content is simply included as calculated above. In any case, the wet acid gas composition is to be used in the metering calculations of the acid gas stream at low pressure. This stream is then converted to a dry basis for reporting purposes.

11.4.4.1 Approved Sulphur Recovery Plants

The production of liquid sulphur must be determined by gauging the liquid sulphur level in sulphur production and storage pits or from weigh bills of shipments by truck or sulphur railroad tank cars, plus inventory changes in the pit.

Meters designed for the expected flow conditions and range must be used to measure sweet and sour gas flared if the average flow rate is greater than 0.5 10^3 m^3/d on a yearly basis. This generally requires a high turndown ratio meter or a combination of a high-range and a low-range meter. A separate acid gas meter designed for the expected flow conditions and range must be used to measure acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume.

The emissions from the sulphur plant emission stack must be monitored for flow rate and SO_2 concentrations.

The emissions from the vapours from the produced water storage tank are those that were estimated to be contained in the produced sour water in the plant inlet calculations. These emissions must be reported as flared gas when this gas is not recycled or directed to the incinerator. If the vapours from the water storage tank are recovered through a vapour recovery unit and are injected into a sour plant process stream, they do not form a separate part of the sulphur outlet of the plant but would still be a part of the sulphur inlet.

The sum of the sulphur contained in the above points must be the sulphur out of the plant. The difference between sulphur in and sulphur out of the plant must be no greater than ±5% if the actual inlet is $\geq$ 1 t/d or ±20% if the actual inlet is < 1 t/d. The acid gas sent to the sulphur plant is to be reported as shrinkage (SHR), and acid gas flaring at the plant is to be reported as "FLARE" on the PRA.

11.4.4.2 Approved Acid Gas Flaring Plants

Plants approved for flaring of acid gas must meter the acid gas leaving the reflux drum of the sweetening process train. The meter calculation procedure must include the effect of the water vapour content in the acid gas at reflux drum pressure and temperature. It is recommended that the concentration of the H_2S content of the acid gas stream be checked at least once per week by Tutweiler by a person trained in the use of the technique and the calculation procedure to determine the H_2S concentration in the acid gas. A gas chromatograph may also be used for this analysis. Plants slipping CO_2 into the sales gas or receiving sour gas from different pools having different H_2S concentrations in the sour inlet gas may need to determine the H_2S concentration in the acid gas more often. A file must be set up to provide a record of the H_2S analysis determinations for inspection by the ERCB.

Meters designed for the expected flow conditions and range must be used to measure sweet and sour gas flared if the average flow rate is greater than 0.5 10^3 m^3/d on a yearly basis. This generally requires a high turndown ratio meter or a combination of a high-range and a low-range meter.

The emissions from the vapours from the produced water storage tank are those that were estimated to be contained in the produced sour water in the plant inlet calculations and must also be reported as flared gas if > 0.05 t/d. If the vapours from the water storage tank are recovered through a vapour recovery unit and are injected into a sour plant process stream, they do not form a separate part of the sulphur out of the plant.

The sum of the sulphur contained in the above points must be the sulphur out of the plant. The difference between sulphur in and sulphur out of the plant must be no greater than ±5% if the actual inlet is $\geq$ 1 t/d or ±20% if the actual inlet is < 1 t/d. The acid gas flared is to be reported on the PRA as shrinkage (SHR) and reported as "Flared" on the S30 report.

11.4.4.3 Approved Acid Gas Injection Plants

Plants approved for injection of acid gas into downhole injection wells must meter the acid gas leaving the reflux drum of the sweetening process train or at some point in the process piping at the plant site. If the gas is metered before the first stage of compression, the meter calculation procedure must include the effect of the water vapour content in the acid gas at the reflux drum pressure and temperature. It is recommended that the concentration of the H_2S content of the acid gas stream be checked at least once per week by Tutweiler or gas chromatography by a person trained in the use of the technique and the calculation procedure to determine the H_2S concentration in the acid gas. Plants slipping CO_2 into the sales gas or receiving sour gas from different pools having different H_2S concentrations in the sour inlet gas may need to determine the H_2S concentration in the acid gas more often than once per week. A file must be set up to provide a record of the Tutweiler determinations for inspection by the ERCB.

Once the acid gas is compressed, it must be measured before injection into each well. If there is more than one injection well, each well must have its own injection measurement at the well site. If sour water is injected together with the acid gas, they must be separately measured before commingling. See below, including Figure 11.3, for various scenarios.

Scenario 1 – Acid gas meter at plant/facility is before compression. Injection wellhead meter is required and can be used as the beginning of the ABIF injection facility.

Scenario 2 – Acid gas meter at plant/facility is after compression and the injection well lease site is not attached to or on the same plant/facility lease. This acid gas meter can be used as the beginning of the ABIF facility; injection wellhead meter is required. Metering difference is to be reported at the ABIF facility.

Scenario 3 – Acid gas meter at plant/facility is after compression and the injection well lease site is attached to or on the same plant/facility lease. This acid gas meter can be used as the beginning of the ABIF facility; injection wellhead meter is not required.

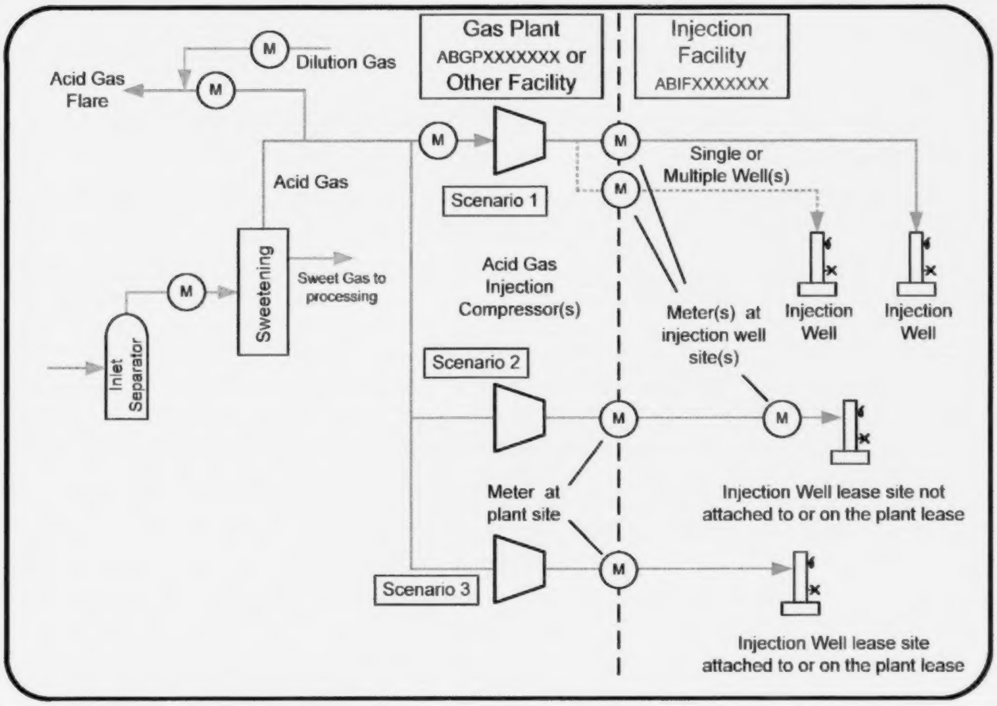

Gas Plant
ABGPXXXXXXX or
Other Facility
Injection
Facility
ABIFXXXXXXX
Dilution Gas
Acid Gas
Flare
M
Acid Gas
Scenario 1
Single or
Multiple Well(s)
Sweetening
Sweet Gas to
processing
Inlet
Separator
Acid Gas
Injection
Compressor(s)
Meter(s) at
injection well
site(s)
Injection
Well
Injection
Well
Scenario 2
Meter at
plant site
Injection Well lease site not
attached to or on the plant lease
Scenario 3
Injection Well lease site
attached to or on the plant lease

Figure 11.3. Acid gas injection measurement scenarios

For those operators that do not have the required acid gas injection measurement at the well site, they have until April 18, 2012, to install the required measurement equipment.

Meters designed for the expected flow conditions and range must be used to measure sweet and sour gas flared if the average flared gas flow rate is greater than 0.5 10^3 m^3/d on a yearly basis. This generally requires a high turndown ratio meter or a combination of a high-range and a low-range meter. A separate acid gas meter designed for the expected flow conditions and range must be used to measure acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume.

The emissions from the vapours from the produced water storage tank are those that were estimated to be contained in the produced sour water in the plant inlet calculations and must also be reported as flared gas if > 0.05 t/d. If the vapours from the water storage tank are recovered through a vapour recovery unit and are injected into a sour plant process stream, they do not form a separate part of the sulphur out of the plant.

The sum of the sulphur contained in the above points must be the sulphur out of the plant. The difference between sulphur in and sulphur out of the plant must be no greater than ±5% if the actual inlet is ≥ 1 t/d or ±20% if the actual inlet is < 1 t/d. The acid gas injected is to be reported as a disposition (DISP) to the injection facility, and acid gas flaring at the plant is to be reported as "FLARE" on the PRA.

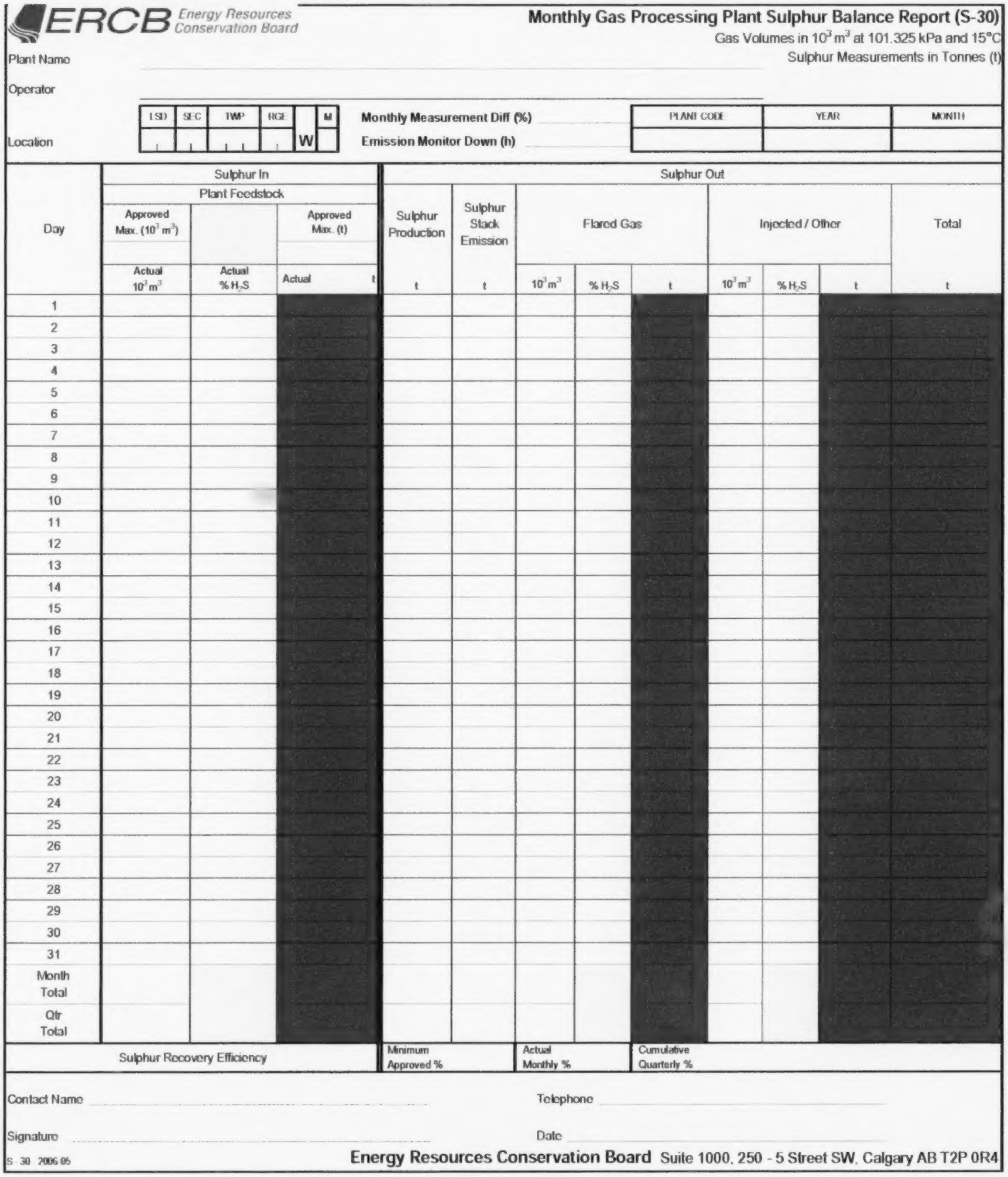
11.5 Production Data Verification and Audit Trail

The field data, records, any calculations or estimations, and EFM records relating to ERCB-required production data submitted to the PRA and the ERCB S-30 reports must be kept for inspection upon request. The records verification and audit trails must be in accordance with the following:

- Proving/calibration records: any records and documentation produced in the proving/calibration of meters and calibration of the prover and all peripheral devices (if the prover and peripheral devices are owned and operated by the licensee)
- Delivery and receipt records: any records and documentation produced in the determination of delivery or receipt volumes/tonnage
- Estimation records: any records and documentation related to the estimation of reported volume/tonnage, including estimation methodology, record of event, and approvals
- Pit gauging records: any records and documentation produced in the determination of reported volume/tonnage
- Volume/tonnage loss records: any records and documentation for volumes lost due to incidents such as spills and fires
- EFM: any records and documentation (electronic, magnetic, or paper form) produced in the determination of measured volume/tonnage in accordance with the EFM requirements in Section 4.3.6 for gas and Section 6.8 for liquids.

11.6 How to Complete the S-30 Monthly Gas Processing Plant Sulphur Balance Report

The S-30 Monthly Gas Processing Plant Sulphur Balance Report below must be submitted to the ERCB using the electronic Digital Data Submission (DDS) system under "Submit Monthly Sulphur Balance Reporting," according to the instructions that follow the form.



ERCB Energy Resources Conservation Board

Monthly Gas Processing Plant Sulphur Balance Report (S-30)

Gas Volumes in 10^3 m^3 at 101.325 kPa and 15°C

Sulphur Measurements in Tonnes (t)

Plant Name

Operator

Location LSD SEC TWP RGE W M

Monthly Measurement Diff (%)

Emission Monitor Down (h)

PLANT CODE	YEAR	MONTH

Day	Sulphur In: Plant Feedstock Approved Max. (10^3 m^3) Actual 10^3 m^3	Actual % H_2S	Approved Max. (t) Actual t	Sulphur Out: Sulphur Production t	Sulphur Stack Emission t	Flared Gas 10^3 m^3	Flared Gas % H_2S	Flared Gas t	Injected / Other 10^3 m^3	Injected / Other % H_2S	Injected / Other t	Total t
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
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23												
24												
25												
26												
27												
28												
29												
30												
31												
Month Total												
Qtr Total												

Sulphur Recovery Efficiency	Minimum Approved %	Actual Monthly %	Cumulative Quarterly %

Contact Name

Telephone

Signature

Date

S-30 2006 05

Energy Resources Conservation Board Suite 1000, 250 - 5 Street SW, Calgary AB T2P 0R4

How to Complete the S-30 Monthly Gas Processing Plant Sulphur Balance Report

Identification

Plant Name	Enter the name of the gas processing plant as given on your gas processing facility approval or from *ST50: Gas Processing Plants in Alberta* (typically licensee name and the first field name).
Operator	Enter the operator name.
Location	Enter the legal description of the plant as shown on the approval.
Monthly Measurement Difference (%)	This field will be calculated using the following formula: Monthly measurement difference (%) = [Monthly sulphur in (t) – Monthly sulphur out total (t)] ÷ Monthly sulphur in (t)
Emission Monitor Down (h)	Enter the number of hours the continuous stack emission monitor (CSEM) was not in service during the reporting month.
Plant Code	Enter the gas processing plant facility code. The field size is 4 numeric characters. • The facility code must exist on the PRA.
Year and Month	Enter the 4-digit year and the 2-digit number of the month being reported. The field size is 6 numeric characters.

Reporting Data (General)

	You must file an S-30 report if you are an operator of a gas processing plant in which raw gas is processed for the removal of H_2S.
	Report gas volumes in 10^3 m^3 at 101.325 kPa pressure and 15°C.
	Report sulphur in tonnes (t) to 1 decimal place, with the option to report to 2 decimal places if required to meet measurement difference requirements.
Day	Enter the data on the row of the corresponding day of the month.

Sulphur In

Plant Feedstock—Approved Maximum (10^3 m^3)	Enter the approved maximum volume of plant feedstock (raw gas plus gas equivalent of inlet condensate), as stated in the approval or the most recent application approved (see Schedule 2, *Directive 056: Energy Development Applications and Schedules*) in 10^3 m^3 to 1 decimal place.

Plant Feedstock—Approved Maximum (t)	Enter the approved maximum of inlet sulphur in tonnes per day to 1 decimal place, as stated in the approval or the most recent application approved (see Schedule 2, *Directive 056*).
	Enter the daily values for sulphur inlet and outlet as detailed below in the row alongside each appropriate date.
Plant Feedstock (10^3 m^3)	Enter the actual volume of plant feedstock (raw gas plus gas equivalent of inlet condensate) received by the plant on this day in 10^3 m^3 to 1 decimal place (see Section 8.3). This must not be entered as a daily average volume for the entire month.
Plant Feedstock (% H_2S)	Enter the daily percentage of H_2S contained in the recombined plant feedstock (raw gas and condensate and/or water) on this day to 1 decimal place; if less than 0.10%, enter the percentage to 4 decimal places.
Plant Feedstock (t)	This field will be calculated using the following formula: Sulphur (t) = Plant feedstock volume (10^3 m^3) × Recombined H_2S% × 1.35592 (Conversion factor) ÷ 100

Sulphur Out

Sulphur Production (t)	Enter the daily sulphur produced in tonnes to 1 decimal place, with the option to report to 2 decimal places if required to meet measurement difference requirements.
Sulphur Stack Emission (t)	Enter the daily sulphur emissions in tonnes to 1 decimal place, with the option to report to 2 decimal places if required to meet measurement difference requirements as recorded by the continuous stack emission monitor (CSEM).
Flared Gas (10^3 m^3)	Enter the amount of gas flared from the plant in 10^3 m^3 to 1 decimal place. • Include all sour gas flared, • In this column, also report acid gas flared from plants that do not recover sulphur.
Flared Gas (% H_2S)	Enter the daily percentage of H_2S contained in the flared gas to 1 decimal place.
Flared Gas (t)	This field will be calculated using the following formula: Sulphur (t) = Flared gas volume (10^3 m^3) × Flared gas H_2S% × 1.35592 (Conversion factor) ÷100

Injected/Other (10^3 m^3)

Enter the daily volume of sulphur injected to subsurface formations or disposed of in any manner other than described above (e.g., nonregenerative sweetening) in 10^3 m^3 to 1 decimal place.

- Include all sour gas injected.
- In this column, also report acid gas injected from plants that do not recover sulphur.
- "Other" disposition, if used, must be identified and separately quantified (monthly total) as part of the S-30 submission.

Injected/Other (% H_2S)

Enter the daily percentage of H_2S contained in the injected gas to 1 decimal place.

Injected/Other (t)

This field will be calculated using the following formula:

$$\text{Sulphur (t)} = \text{Injected gas volume } (10^3\ m^3) \times \text{Injected gas } H_2S\% \times 1.35592 \text{ (Conversion factor)} \div 100$$

Total (t)

This field will be calculated using the following formula:

$$\text{Total daily tonnage} = \text{Sulphur production (t)} + \text{Sulphur stack emission (t)} + \text{Flared gas (t)} + \text{Injected/others (t)}$$

Month Total

This field will be calculated automatically.

Quarterly Total

This field will be calculated automatically.

- The ERCB defines the quarters as January–March; April–June; July–September; and October–December. Thus, for example, if you are filing for February, enter the monthly total for January plus February; if filing for March, enter the monthly total for January plus February plus March; if filing for April, enter the monthly total only for April.

Sulphur Recovery Efficiency

Complete this section only if the plant recovers elemental sulphur or injects acid gas.

Minimum Approved %

Enter the approved minimum quarterly sulphur recovery efficiency as stated in the approval or from *ST50: Gas Processing Plants in Alberta*.

Actual Monthly %

This field will be calculated using the following formula:

$$\text{Actual monthly sulphur recovery efficiency} = \frac{(\text{Sulphur production (t)} + \text{Sulphur injected}) \times 100}{\text{Sulphur production (t)} + \text{Emissions (t)} + \text{Flared (t)} + \text{Sulphur injected}}$$

Cumulative Quarterly %

This field will be calculated automatically.

Contact

Enter the full name of the person who accepts responsibility and to whom inquiries regarding this report should be directed.

Sign the statement.

Enter the person's business telephone number, including area code. (Please print.)

Enter the date this S-30 report is completed.

When to File

Your monthly S-30 report must be submitted to the ERCB Technical Operations Group via DDS by 4:30 p.m. on the 18th day of the month following the month being reported. If the 18th day is not a business day, you must submit on the first business day after the 18th.

12 Heavy Oil Measurement

This section presents the requirements and exceptions for heavy oil and crude bitumen facilities. This section does not cover crude bitumen production through mining.

The term "heavy oil" in this section includes crude bitumen (other than that produced through mining or in situ processes). See Glossary for definition of heavy oil and crude bitumen.

There are two general categories for the production of heavy oil: primary/secondary (includes cold production and water flood techniques) and in situ thermal and solvent oil sands schemes.

Blending of heavy oil with lighter hydrocarbon liquids may occur. The lighter hydrocarbon liquids, often called diluent or condensate, are used to reduce the viscosity of the heavy oil and make it easier to process and/or transport.

12.1 General Measurement Requirements

In all cases, a licensee must measure produced heavy oil volumes, unless otherwise stated in this directive. The ERCB will consider a heavy oil measurement system to be in compliance if the fuel measurement requirements in Sections 1.7 and 4.2, the calibration and proving requirements in Section 2, and measurement requirements in Section 14 and in this section are met.

12.1.1 Temperature Correction Requirements

See Section 14.4: Temperature Correction Requirements

Exception

If testing heavy oil by test tanks, temperature correction is not required. However, the operator must be aware that if the temperatures are elevated above standard conditions, the proration factors will be biased by the amount of the temperature correction (approximately 0.07 per cent per degree Celsius [%/°C] at a density of 920 kg/m^3). See Section 3.1.2 for required amendments.

12.1.2 Pressure Correction Requirements

See Section 14.5: Pressure Correction Requirements.

12.1.3 EFM Requirements

See Section 14.10: Electronic Flow Measurement for Liquid Systems.

12.1.4 Diluent/Condensate Receipts and Blending

Blending occurs when two oils of dissimilar properties are mixed. This mixing result in volumetric discrepancies from the ideal combination, which would yield a volume that would be the sum of the two products. The discrepancy is usually shrinkage, which is the result of smaller molecules of the lighter hydrocarbon filling in the voids or spaces between larger molecules of the heavier hydrocarbon. The result is a combined liquid volume that is less than the sum of the two original volumes. This shrinkage must be determined and properly applied to volumes making up the liquid to ensure proper allocation and reporting.

12.1.4.1 Hydrocarbon Blending and Flashing Shrinkage

Generally, heavy oil is not significantly affected by shrinkage caused by flashing of light ends. However, there is always potential for shrinkage depending on the actual operating pressure at which the wells are produced. Operators should evaluate each facility based on its operating characteristics. See Section 14.3 for details.

12.1.5 Water Measurement

Operators must have in place proper procedures to measure produced water, water receipts, and water injection/disposal to ensure that the information used for reporting is accurate. See Section 1 for measurement accuracy requirements.

As sand may constitute a significant percentage in the S&W content of heavy oil production, it is expected that operators will follow Section 14.6 and 14.8 requirements for sampling and analysis to quantify these volumes. The sand volume is to be included as part of the S&W determination and reported as water.

12.1.6 Well Proration Testing

For heavy oil well testing, operators must follow the testing frequency requirements in Section 6.4.4. For additional heavy oil well testing requirements, see Sections 12.2.4.

12.1.7 Heavy Oil Receipt, Delivery, or Sales

This includes the delivery or receipt of heavy oil (diluted or non-diluted), diluent, or other hydrocarbon products. For the single point measurement uncertainty of these measurement points see Section 12.2.3.

12.2 Primary and Secondary Production (Non-Thermal In Situ Oil Sands Schemes)

Well effluent produced from heavy oil wells using natural or other drive mechanisms, such as water-flood wells, flowing wells, or wells with conventional lifting technologies (pump jacks, progressive cavity pumps, submersible pumps, etc.), is considered primary and secondary production. The well effluent could be flow lined to field test satellites or group production facilities, or the fluids could be produced to tanks at surface and trucked out to a treatment facility. These production wells are subject to the same measurement and reporting requirements as conventional oil wells (see Section 6), unless otherwise noted in this section.

12.2.1 Battery Types

Battery types are the same as in Section 6.2.2, with the following exceptions:

12.2.1.1 Single-Well Batteries—PRA Subtype 331 (Disposition = Production)

Oil and water volumes trucked from lease production tanks must be used to calculate the well production reported on the PRA. Where a well is producing as a single-well battery (SWB) to a lease tank, the lease tanks can be considered as part of the reservoir and the inventory in the tanks is not reported. This procedure is referred to as the disposition equals production (disposition = production) accounting method and is only applicable to production within the designated oil sands areas with the well status fluid code "17." Oil and water production are only reported when the fluids are trucked from the lease tank to another location.

If a well is on a restricted gas production order (gas allowables) or has unrecovered load fluids, the disposition = production method may not be appropriate and the reporting of oil and gas production should be done monthly based on inventory change. If there is receipt(s) into the single-well battery, monthly production must be reported based on receipt and inventory volumes and the disposition equals production methodology does not apply.

When using the disposition = production accounting method, it is correct to show hours on production and no production volume if a shipment was not made from a lease tank of a producing well during the reporting period. Conversely, produced fluid removed from a lease tank during a month that a well is shut in is to be shown on the reports as with zero hours of production. Suspended and abandoned heavy oil batteries can report dispositions (and production) up to six months after they become inactive.

12.2.1.2 Paper Batteries—PRA Subtype 343

Paper batteries are developed to reduce the number of reporting entities for submission to the PRA. Paper batteries are made up of multiple single heavy oil well batteries, excluding licensed multiwell batteries or multiple single-well batteries (SWB) on the same lease, that are grouped for reporting purposes into one larger battery. This allows operators to report production and dispositions from a number of individual wells in one battery, thereby reducing the administrative burden. Paper batteries are treated as multiwell group batteries even though the single wells are not on a common production site. On the PRA, a paper battery is to be reported as a subtype 343: Crude Bitumen/Heavy Oil Administrative Grouping.

It is acceptable to move fluids between locations within the same paper battery. These volume movements are not reported to the PRA but must be managed in a field data capture system.

Wells in a paper battery are eligible for reporting using the disposition = production methodology (see Section 12.2.1.1).

As paper batteries are for administrative ease, they must comply with the following criteria:

- Wells within the paper battery must have common equity and royalty.
- No venting or fuel can be reported at the paper battery level. Venting and fuel activity must be reported at the location where it physically occurred, i.e., at the well site.
- Wells within a paper battery must be within a geographic area no larger than 6 contiguous townships.
- The operator must use one of the SWB locations within the paper battery for reporting.

12.2.1.3 Multiwell Group Batteries—PRA Subtype 341

Each well must have its own separation and measurement equipment similar to a single well battery. The disposition = production accounting method may be used for each well when appropriate.

All equipment for the wells in the battery must share a common surface location.

If the disposition = production method is not used or cannot be used, inventory at the group battery is to be reported monthly to the PRA.

12.2.1.4 Multiwell Proration Batteries—PRA Subtype 342

All well production is commingled prior to the total battery oil/emulsion being separated from the gas and measured. Individual monthly well oil and water production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor (see Section 6.4.4).

Inventory at the proration battery is to be reported monthly to the PRA.

Wells included in a proration battery are not eligible for the disposition = production methodology.

12.2.1.5 Thermal In Situ Oil Sands —PRA Subtype 344 or 345

See details in Section 12.3.

12.2.2 Gas Measurement and Reporting

Any single stream of produced gas, flared gas, or vented gas volume exceeding 2.0 10^3 m^3/day must be measured. If the annual average fuel gas usage exceeds 0.5 10^3 m^3/day on a per site basis, the fuel gas must be measured.

For single-well batteries, vented or flared gas at a well site may be reported at the battery level. For a multiwell group, proration, or paper batteries, individual well flared or vented gas must be reported at the well level unless the gas is collected at a common point and then flared or vented. Then it can be reported at the battery level.

If gas measurement is required, the single point measurement uncertainty is ±3%.

12.2.2.1 Single-Well Batteries

For initial well startup, in the absence of suitable reservoir information, monthly tests must be conducted to determine the GOR factor or the hourly rate if gas volumes are not dependent upon oil production volumes (see Section 4.3.5.4) for 6 months or until gas production stabilizes and measurement is required if over 2.0 10^3 m^3/day. If total gas production per well does not exceed 2.0 10^3 m^3/day, the producer may use GOR or hourly rate testing to determine gas volumes. In addition to the measurement of volume, the source of the produced gas must be assessed by analysis to determine whether the gas is solution gas or cap gas. This is especially important if gas lease ownership differs from bitumen lease ownership.

A test of the well (approximately 24 hours) may be conducted such that all the applicable gas and oil volumes produced during the test are measured (including fuel, flared, and vented gas; see Figure 12.1). The gas volume is to be divided by the oil volume to result in the GOR factor or divided by the test hours to obtain an hourly rate. For single-well oil batteries the oil volume used in the determination of the GOR factor can be based upon the monthly total oil production (monthly total volume / hours produced in month x test duration).

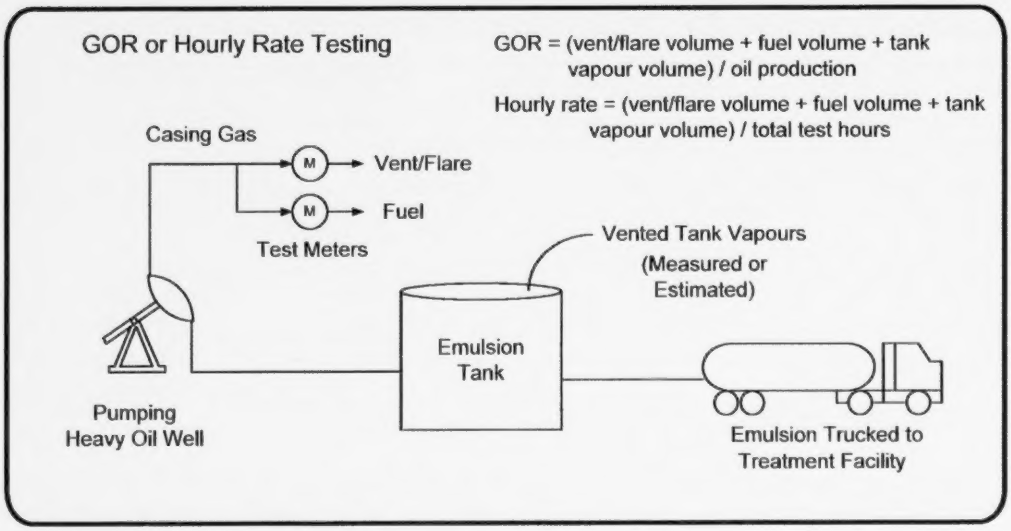

GOR or Hourly Rate Testing
GOR = (vent/flare volume + fuel volume + tank vapour volume) / oil production
Hourly rate = (vent/flare volume + fuel volume + tank vapour volume) / total test hours
Casing Gas
M
Vent/Flare
M
Fuel
Test Meters
Vented Tank Vapours (Measured or Estimated)
Emulsion Tank
Pumping Heavy Oil Well
Emulsion Trucked to Treatment Facility

Figure 12.1. GOR or hourly rate testing schematic

GOR or hourly rate test frequencies are detailed in the table below.

Table 12.1. GOR or hourly rate test frequency requirements

Gas rate (10^3 m^3/d)	Test frequency
≤0.1	Once every 3 years
>0.1 but ≤1.0	Annually
>1.0 but <2.0	Semiannually

12.2.2.2 Multiwell Batteries

If gas disposition is measured at a multiwell proration battery and is sold or used at a point farther on,

- gas production volumes for each well over 2.0 10^3 m^3/day must be tested, unless measured, on a per stream basis at the same frequency as the emulsion testing, or
- if not more than 2.0 10^3 m^3/day, estimated using the well GOR or hourly rate at the same initial frequency as a SWB, and then in accordance with Table 12.1 after stabilization (see Section 12.2.2.1).

If associated gas is flow lined to a central facility or collection point and gas production rates at the point of collection or emission are less than 2.0 10^3 m^3/day and not measured, a battery or facility GOR may be determined, but gas production reporting must be at the individual well level. Initial and updated factors may be determined by any of the applicable tests or procedures described in Section 4.3.5.4 and at the same frequency as a SWB (see Section 12.3.2.1).

12.2.3 Oil and Water Deliveries to a Treatment Facility

Liquid volumes are trucked from single-well batteries, multiwell batteries, and wells within paper batteries to a custom treater or battery. These facilities produce oil, water, and sand for disposal from the trucked-in fluids. Typically, received products are measured using weigh scales or inlet meters but tank gauging could also be used (see Section 10.3). The oil and water densities from every well must be updated in accordance with Section 10.4.4 and the

S&W of the emulsion delivered to these facilities must be determined on a per-load basis (see Sections 14.6 and 14.8).

The single point measurement uncertainty of liquid products received into the cleaning plant is ±1.0%, excluding the effect of S&W and density determination. The single point measurement uncertainty of sales oil delivery point measurement from the treatment facility is ±0.5%.

12.2.4 Well Test Measurement with Tank Gauging or Metering

Wells in primary/secondary production of heavy oil must be tested at the frequency stated in Section 6.4.4. The tests must be conducted in a consistent manner throughout the month and a test must be conducted when there is a change in well parameters (pump speed, work-over, reactivation, flush-by, etc.) as soon as possible.

A water cut must be determined for each test, and collecting a wellhead sample during a test is acceptable. See Sections 14.6 and 14.8.

Temperature correction is not required for well tests using test tanks (see Section 12.1.1).

Tests may be conducted by using a single isolated tank at the well site. The table below may be used by the licensee to determine the height-to-diameter ratio requirements in accordance with Section 14.7.2, with the exception that the accuracy coefficient in this table is a suggested minimum for test fluid volumes.

Table 12.2. Accuracy coefficients for various measurement types for test tanks

Level measurement technique	Accuracy coefficient "a"	Maximum level reporting resolution (mm)
Gauge board	1.6	25
Manual dip of the tank	0.4	10
Electronic (e.g., radar)	0.4	10

The accuracy coefficient "a" can be used in the following equation:

$$V \geq a \times d^2 \quad \text{or } d \leq (V/a)^{0.5}$$

where:

V = test fluid volume in m^3
a = accuracy coefficient
d = tank diameter in metres

On the tank being used for testing, the gauge board float, linkage, and scale must be in good condition. The gauge board markings must be no further than 60 mm apart. For gauge measurement on test tanks, one reading of the gauge board is acceptable for the start and end of the test. Where safe work conditions permit, gauge boards should be read at eye level.

If the well emulsion is to be tested using a meter, the meter must be sized to operate within 20 to 90% of its flow range and installed and operated in accordance with Sections 2.6 and 14.2.

The single point measurement uncertainty of the test emulsion meter is ± 2.0%, excluding the effect of S&W determination.

12.3 Thermal In Situ Oil Sands Operations

Crude bitumen recovery typically requires the injection of steam, sometimes with added solvent or gas.

For thermal production operations, operators deal with a variety of measurement challenges.

- Steam injection may be of variable quality at the wellhead, resulting in systematic errors, and may also be present in the vapour state at production facilities, creating further measurement issues.
- Most thermal projects require the use of a diluent to assist in the separation of water/bitumen emulsions, so bitumen production may not be directly measured at these facilities.
- Produced fluids are at high temperatures, so all measurements must be temperature corrected except for well testing volumes.
- At some facilities, highly abrasive fluids are observed as a result of entrained sand, which can damage meters and introduce systematic errors.
- Injected solvent and gas may be difficult to fully differentiate from produced fluids, especially since the composition of the bitumen can change across a scheme area and vertically within a zone, and can be further changed due to in situ high-temperature reactions.

For the above reasons, the measurement plan at thermal operations must be thoroughly considered.

Directive 042: Measurement, Accounting, and Reporting Plan (MARP) Requirements for Thermal Bitumen Schemes is also an integral part of a scheme's measurement plan. It provides information on the submission and approval requirements of a MARP before facility licensing.

Unless otherwise stated below, all existing thermal in situ facilities must meet the requirements set out in this section by April 18, 2012. For new facilities and expansions to existing facilities, the steam and water measurement requirements are effective immediately.

12.3.1 Definitions

Boiler blowdown – Boilers used in thermal recovery processes typically produce steam with a quality between 75 and 80%. This results in 20 to 25% of the boiler feed water not being vapourized, and in steam-assisted gravity drainage (SAGD) schemes, the resulting liquid is separated from the steam. This separated water stream leaving the boiler is called blowdown and contains more concentrated total dissolved solids, typically 4 to 5 times more, than the boiler feed water.

Camp – For the purpose of this directive, a camp is a residential housing facility for construction and operations workers associated with a thermal injection scheme. Fresh water used by a camp requires a separate licence under the *Water Act*.

Camp wastewater – For the purpose of this directive, camp wastewater is defined as the liquid waste discharged from a camp.

Cold water equivalent (CWE) – All injected water and steam volume measurements corrected to a standard temperature of 15°C and reported in cubic metres (m^3).

Primary measurement – Measurement used to determine a process stream volume that is reported to the PRA.

Scheme – For the purpose of this directive, includes all batteries and injection facilities associated with an ERCB thermal in situ oil sands scheme approval.

Secondary measurement – Alternative measurement or calculation method used to validate the primary measurement volume and used during repair/downtime of primary measurement equipment. This allows operators to identify metering inaccuracies in advance of annual facility turnarounds, meter provings, calibrations, and inspections, resulting in timely repairs.

Steam – For reporting to the PRA, the sum of all steam injection of varying quality, reported in CWE.

Steam quality – The measure of the amount of saturated steam in the vapour phase (mass fraction).

Utility use – For reporting to the PRA as activity [UTIL], the sum of all water used at the injection facility for utility, waste steam, and emissions control and not recovered due to evaporation or venting.

Water balance – ERCB series of calculations performed on the water volume data reported to the PRA to determine all water types and uses. The water balance also determines the imbalance between the total input and total output streams, providing an indication of measurement accuracy and reporting on a facility.

12.3.2 Bitumen, Diluent, or Dilbit Delivery Point Measurement

Each operator is responsible for determining the total bitumen production at its scheme, regardless of whether another party is responsible for operation of the delivery point measurement. The delivery and receipts of bitumen, diluent, and/or dilbit all affect the final determination of bitumen production of a scheme. The following are requirements for delivery and receipt points of diluent, bitumen, and/or dilbit:

Delivery/receipt point measurement must meet a single point measurement uncertainty of 0.5% and must be proved in accordance with Section 2.6 where applicable.

Density measurement must be taken on the delivery/receipt product using one of the following methods:

- on-line densitometer or coriolis meter
- ASTM D4052 - Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter
- ASTM D5002 - Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer
- ASTM D1298/6822 - Standard Test Method for Density and Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.

Water content must be determined for delivery/receipt product using the following methods:

- ASTM D95 - Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation
- ASTM D4006 - Standard Test Method for Water in Crude Oil by Distillation
- ASTM D4377 - Standard Test Method for Water in Crude Oils by Potentiometric Karl Fischer Titration

Solids content must be determined for delivery/receipt product using the following methods:

- ASTM D4807 – Standard Test Method for Sediment in Crude Oil by Membrane Filtration; applicable to samples with low mineral content
- Mineral by Centrifuge Separation; applicable to samples with high mineral content.

For static testing methods, all samples for density, solids, and water must be obtained using proportional sampling and adhere to all requirements in Section 10.4.1.

Trucked in volumes must adhere to sampling requirements in Section 10.4.1 or 10.4.2.

Determination of shrinkage must be consistent with Section 14.3.

Sand volume is to be included as part of the S&W determination and reported as water, as stated in Section 12.2.5.

All measurement methods must be conducted in a manner satisfactory to the ERCB. Additional requirements may apply depending on circumstances specific to each project through MARP approvals or site-specific requests.

12.3.3 Gas Measurement

Gas production measurement from thermal wells can be problematic, particularly at high temperatures where steam and solvent may be present with the gas and the combined flow of gas, steam, and/or solvent would be metered together.

For multiwell proration facilities, the group gas measurement can be used to prorate back to well gas test rates using one of the following methods:

- If a test separator exists, the total battery gas is prorated back based on the individual test gas rates after subtracting the steam produced with the gas and any lift gas volumes.
- The individual well GOR may be used in accordance with Section 12.2.2.
- If test gas rates are not consistent and not used or well gas is not measured but total well fluid production and water cut can be determined at the battery, well gas production may be determined using a battery-level GOR. The battery-level GOR and the application to each well can be calculated as follows and will result in a gas proration of 1.00000:

  Battery GOR = Total monthly measured produced gas at battery / Total monthly measured produced oil at battery

  Well gas volume = Battery GOR x Well prorated (reported) oil volume

The battery-level GOR can only be used if the criteria below are met:

- there is common ownership of all the wells and the battery (no equity issues), and
- there are no gas sales of the produced gas that would trigger a gas royalty payment.

Total gas flared must be measured and total vented gas must be reported and determined using sound engineering practices.

Gas can be injected into the bitumen reservoir for a variety of different purposes over the life of a well. If gas is injected into the bitumen reservoir (other than lift gas), it must be measured and reported. If lift gas is used, the total lift gas volume must be measured and netted off the total produced gas volume before prorating to the wells.

The single point measurement uncertainty for gas produced at a battery or injected at a wellhead is ±3%.

It is expected that when operators are injecting gas into the reservoir, there is a methodology in place to determine the resulting production of the injected gas. A *Directive 042* application must be submitted to address the details of the gas injection and resulting production. If a MARP already exists, an update must be submitted for ERCB approval prior to commencing any gas injection.

12.3.4 Steam Measurement

Direct measurement of injected steam is challenging. Operators must contend with steam losses, unmetered utility steam, and changes in steam quality from steam generator to wellhead. Steam must be reported as a CWE at 15°C. If it is delivered from another facility for injection, it must be reported on the PRA as a receipt of the product [STEAM].

The steam injected into each well must be measured on a per-well basis and reported monthly. When measuring wellhead injected steam, the devices used must have a single point measurement uncertainty of ±5% at the time of installation. Wellhead injection meters with no internal moving parts must have the instrumentation calibrated annually, or before every steam cycle.

At a minimum of once every two steam cycles, operators that use cyclic steam stimulation (CSS) as a recovery method must visually inspect the primary measurement element of one wellhead steam injection meter for every five wells on a pad. At a minimum of once per year, steam assisted gravity drainage (SAGD) or other thermal operations must visually inspect the primary element of one wellhead steam injection meter for every five wells on a pad (see Section 2.5.2.1 for exception). For example, pads that have 6 to 10 wells would require a two well sample set, 11 to 15 wells a three well sample set, and so forth. The well(s) chosen to act as a sample set on a given pad must be representative and not have been selected in the previous five years. Should any of the inspected sample set meters be compromised, the operator is required to service (clean or replace) all wellhead injection meters included on the pad within 12 months of discovering the compromised meter. Visual evidence of the primary flow element condition during the meter inspections must be kept on site and made available to the ERCB upon request.

Radiography, optical techniques, or other nonintrusive methods may be used in lieu of physical inspections provided that the images are of sufficient quality to discern any damage to the primary measurement element or the presence of scale. Should any of the inspected sample set meters be compromised, the operator is required to inspect (nonintrusively) all

wellhead injection meters on that pad within one month of discovering the compromised meter. The operator is required to service (clean or replace) within one month those meters that showed damage, scaling, or yielded inconclusive results. Other verification methods will be considered on a case-by-case basis.

The wellhead volumes reported to the PRA must be prorated from the total steam volume leaving the steam plant. The monthly facility proration factor and the data used in its calculation must be kept on site and made available to the ERCB upon request. The volume of steam leaving the steam plant may be determined from

- total steam volume leaving the steam plant separator, or
- boiler feed water and boiler blowdown.

A maximum single point measurement uncertainty of ± 2% is required for

- steam entering or leaving the injection facility, excluding wellhead injection, e.g., steam transferred to a battery or to or from another injection facility;
- steam used for emissions control at the injection facility (e.g., NOx), unless the volume is less than 2.0% of the injection facility's total water out, in which case it may be estimated using sound engineering practices; and
- steam leaving a steam plant.

All steam measurement devices must be calibrated/proved/verified on an annual basis or as otherwise stated in Section 2.5 or above.

12.3.5 Water Measurement

The measurement of water at thermal in situ facilities is a key component to evaluating the plant performance and compliance with approvals and regulations. Therefore, a higher degree of accuracy is required than at conventional production operations.

A maximum single point measurement uncertainty of 2.0% is required for the following water streams at injection facilities associated with thermal in situ oil sands schemes:

- fresh, brackish, and produced water entering or leaving the injection facility;
- water injection/disposal;
- boiler feed water and boiler blowdown;
- water used for emissions control at the injection facility (e.g. NOx), unless the volume is less than 2.0% of the injection facility's total water OUT, in which case it may be estimated using sound engineering practices;
- camp wastewater entering an injection facility, unless the volume is less than 2.0% of the injection facility's total water OUT, in which case it may be estimated using sound engineering practices.
- freshwater diversion points licensed by Alberta Environment **and Sustainable Resource Development** under the *Water Act*.

Upon application, the ERCB may approve alternative methods for determination of the above water stream volumes if it is satisfied that they can be determined with a maximum uncertainty of 2.0% (e.g., calculating produced water by subtracting measured fresh and/or brackish water from a measured mixed water stream).

A maximum single point measurement uncertainty of 5.0% is required for all other water uses reported to the PRA, except if the water streams are small (less than 2.0% of the total OUT in the facility water balance), in which case they may be estimated using sound engineering practices.

All water measurement devices must be calibrated/proved/verified on an annual basis or as otherwise stated in Sections 2.6 and 2.10.

12.3.6 Water/Steam Primary and Secondary Measurement

For produced water entering an injection facility and steam leaving a steam plant, primary measurement must be verified with secondary measurement. This secondary measurement is subject to the same maximum single point measurement uncertainty as the primary measurement. On a monthly basis, differences between the primary and secondary measurement of greater than 5.0% must be reconciled using sound engineering practices. The reconciliation must be recorded and made available to the ERCB upon request.

If both the primary and secondary measurements are on the same pipe run, the operator must use differing measurement technologies to aid in preventing measurement failures from the same mechanism.

If the design of the metering system includes the provision to inspect, conduct maintenance, and repair the primary measurement element without shutting in the stream flow (i.e., meter bypass) and repair of the meter can be completed within two weeks of ceasing primary measurement, then secondary measurement is not required.

12.3.7 Solvent Measurement

The addition of solvent(s) to steam injection can accelerate and improve the recovery of crude bitumen. Injected substances used as solvents can include, but are not limited to, ethane, propane, butane, and carbon dioxide or some combination of the above.

Individual types of solvents injected into the formation must be measured prior to mixing with steam and/or other solvents. Operators must comply with the standards of accuracy requirements in Section 1 and the liquid solvent injection requirements below.

The determination of produced solvent is key to evaluating process performance and economics and determining bitumen production volumes. The determination of solvent production is complex and includes, but is not limited to, volumetric measurement, sampling, and compositional analysis. Consequently, a *Directive 042* application must be submitted to address the details of the solvent injection and corresponding production. If a MARP already exists, an update must be submitted for ERCB approval prior to commencing any solvent injection.

The single point measurement uncertainty for liquid solvent injection is ± 2%.

All injected solvents measured in the gaseous phase are subject to requirements in Sections 12.3.2 and 12.3.3.

All solvent injection measurement devices must be calibrated/proved/verified on an annual basis in accordance with Section 2.

12.3.8 Production Measurement

The need for accurate production measurement for bitumen, water, and gas is no different from that for conventional facilities. However, due to the nature of the bitumen and the high production temperature, it is impractical to prove meters in the field in a manner used for conventional oil. Proving trucks cannot handle high temperature fluids or the high viscosity of cooled bitumen. Therefore, for thermal in situ oil production, annual verification of measurement devices is sufficient provided that the facility proration factor is within the targets specified in Section 12.4; if targets are not being met, more frequent verification may be required. For delivery point measurement, sales, or LACT, see Sections 12.3.2 and 14.

Verification can be achieved using

- internal diagnostics of the measurement device if present to check the **structural** integrity of the primary measurement element,
- bench proving,
- other ERCB-approved methods.

The single point measurement uncertainty for emulsion is ±2%, excluding the effects of steam and hydrocarbon vapours, as well as the effect of S&W determination.

Determination of S&W from wells faces the same challenges as the production measurement. For this reason, it is necessary that S&W methods take into account the temperature and pressure of the sampled emulsion. All manual S&W samples must be adequately cooled to mitigate the flashing of components. If S&W is determined using an on-line analyzer, provisions to take manual samples must be present to compare against the analyzer if necessary. On-line analyzers are to be calibrated annually.

12.3.9 Well Testing

Well testing in enhanced thermal operations can only be performed under certain conditions and is typically done using a test separation vessel. Operators using test separation to determine well production must comply with the following:

- They may have no more than 12 production wells tied into a single test separator. At minimum, each production well must have one valid testing hour for every 20 hours the well is in operation. Operations that currently exceed the 12 production well requirement and have scheme approval to operate in this manner are grandfathered for existing infrastructure.
- One well must be in the test cycle at all times.
- The test duration must be optimized to obtain as many representative production well tests as possible for each month.
- Sufficient time must be provided between tests to purge the test separator of the emulsion from the previous test.
- S&W must be determined for each test.
- Test durations and methods must be reassessed annually to verify that current practices are sufficient to obtain representative data, and this information must be made available to the ERCB upon request.

Notwithstanding the above, at certain points in a high-pressure cyclic steam well's production cycle, the process fluids cannot be tested due to high temperatures. In such instances, engineering estimates may be used until tests can be conducted.

Operators must use test separation for well fluid determination unless otherwise approved by the ERCB. If a different method of production measurement is proposed, it must be explicitly stated in the *Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project* application and included within the conceptual measurement plan. The proposed measurement method will be finalized during the *Directive 042* application process.

12.3.10 Proration Factors

The proration factor target range for both oil and water is 0.85 to 1.15. Previously, the target range for thermal in situ facilities was 0.75 to 1.25. However, with current technology and operating experience, the ERCB expects that a target range of 0.85 and 1.15 is achievable. If the proration targets are not being met, the ERCB may require an investigation to determine why. Action required by the operator may include, but is not limited to,

- verifying S&W measurement practices,
- verifying related fluid measurement system performance,
- proving or calibration of measurement equipment, and
- inspecting the primary measurement element for meters with no internal moving parts.

12.4 Uncertainty and Proration Factor Summary

Table 12.3. Summary of single point measurement uncertainty

Measurement type	Single point measurement uncertainty
Gas in primary/secondary production or injection	±3%
Emulsion test using metering	±2%, excluding the effect of S&W determination
Primary/secondary production emulsion into treatment facilities (Cold heavy oil/bitumen production only)	±1%, excluding the effect of density and S&W determination
Clean oil/ bitumen sales - primary, secondary, and in situ recovery	±0.5%
Wellhead steam injection (CWE)	±5%, excluding the effect of steam quality
All other steam measurement, including total steam leaving a steam plant separator (CWE)	±2%
Liquid solvent injection	±2%
Fresh, brackish, produced water into injection facilities	±2%
Boiler feed water, boiler blowdown	±2%
Water disposal	±2%

Table 12.4. Summary of proration factors

Facility type	Proration factors
In situ production	0.85 – 1.15 oil 0.85 – 1.15 water

13 Condensate and High Vapour Pressure Liquid Measurement and Reporting

This section presents the requirements and exceptions for condensate measurement and reporting associated with gas well production.

Condensate is a generic term used to describe various types of hydrocarbon liquid products. This section is intended to clarify the various definitions of condensate and address the measurement and reporting requirements. See Glossary in Appendix 3 for definition of high vapour pressure liquids, NGL, LPG, ethane, propane, butane, and pentane plus.

13.1 Definitions

Field condensate: For Crown Royalty purposes, field condensate (in some documents, this is simply referred to as condensate) is defined as "products obtained from natural gas or solution gas before they are delivered to a gathering system." Typically, Field Condensate is a hydrocarbon liquid separated from raw production at a well or a group measurement point, stabilized in a tank, and sold or otherwise disposed of without further processing before entering a gas gathering system. See *Natural Gas Royalty Regulation* 2002, AR 220/2002 (*NGRR*), under the *Mines and Minerals Act*.

Condensate, separator liquids: Separator liquids are a mixture of hydrocarbon components that remain in a liquid state under the equilibrium pressure and temperature (P&T) conditions established in a two- or three-phase separator. The composition and physical properties of separator liquids are highly variable and are a function of separator inlet fluid composition and separator P&T conditions.

Condensate, stock tank liquids: Stock tank liquids are a mixture of hydrocarbon components that remain in a liquid state under the equilibrium P&T conditions in a low-pressure vessel or atmospheric-pressure tank. The composition and physical properties of stock tank fluids are a function of the composition of the high-pressure fluid from which they were derived.

Condensate, stabilized liquids: Stabilized liquids are a mixture of hydrocarbon components that remain in the liquid state following single-stage flash evaporation. Stabilized condensate is expected to have low concentrations of butane minus (C4-) components. The composition and physical properties of the stabilized condensate is a function of the equilibrium P&T conditions of the stabilizer and the composition of the stabilizer feed from which it was derived.

13.2 General Measurement and Reporting Requirements

13.2.1 Measurement Requirements

For measurement of condensate and high vapour pressure liquids at all accounting locations within the upstream oil and gas facilities, the ERCB will consider the measurement system to be in compliance if the measurement requirements in Sections 1.7.2 and 4.2, the calibration and proving requirements in Section 2, the design and installation of liquid (oil) measurement requirements in Section 14, the sampling and analysis requirements in Section 8, and the trucked liquid requirements in Section 10 are met.

13.2.2 Reporting Requirements

Hydrocarbon liquid production can be reported as a gas or liquid or both, depending on how it is disposed (see *Directive 007: Volumetric and Infrastructure Requirements* (December 2007)). The general rules are as follows for PRA reporting:

- Hydrocarbon liquids produced from a gas well producing oil must be reported as a liquid oil volume at the well level, regardless of whether they are trucked or recombined. The *Petroleum Royalty Regulation 2008*, AR 248/90 (PRR), under the *Mines and Minerals Act* applies for Crown royalty.
- Hydrocarbon liquids received from wells designated as VGWL OIL that are separated at group separation points at batteries or gathering systems and directed to a tank for disposition are considered OIL and must be reported as a liquid volume.
- Hydrocarbon liquids produced and separated from a gas well or at the group measurement points of multiwell gas proration or effluent proration batteries producing condensate, measured, and recombined with the gas or trucked out for further processing must be converted to and reported as gas production (see Cases 1 and 5 below). The *NGRR* applies for Crown royalty.
- Hydrocarbon liquids produced and separated from a gas well producing condensate or at the group measurement points of multiwell gas proration or effluent proration batteries, stored in a tank, and trucked for sales are considered field condensate and must be reported as a liquid condensate volume at the well level (see Cases 2 and 3 below). The *NGRR* applies for Crown royalty.
- Hydrocarbon liquids separated from a gas gathering system at group separation points and stored in a tank for disposition are considered pentanes plus (C5+) and must be reported as a liquid volume (see Case 4 below). The *NGRR* applies for Crown royalty.
- Hydrocarbon liquids recovered from processing at a gas processing plant are considered by-products of processing and must be reported as a liquid volume. The *NGRR* applies for Crown royalty.
- Load condensate (or oil or water) received, injected, recovered, separated, and stored in a tank at a measured gas well is to report load fluids, in accordance with *Directive 007* on-line supplement Appendix 8 reporting procedures.
- Load condensate received from an outside source at any gas well, injected, recovered, separated, recombined with production, and sent to a gas plant must report condensate receipt at the battery level and report disposition of C5+ with From/To of "ABGE" to balance the condensate receipt to avoid double paying royalty.
- Load LPG, NGL, C3, or C4 received from an outside source at any gas well, injected, recovered, separated, recombined with production, and sent to a gas plant must report hydrocarbon receipt at the battery level and report disposition of the hydrocarbon with From/To of "ABGE" to balance the hydrocarbon receipt to avoid double paying royalty.
- Load oil received from an outside source at any gas well, injected, recovered, recombined with production, and sent to a gas plant must report oil receipt at the battery level and report disposition of the oil.

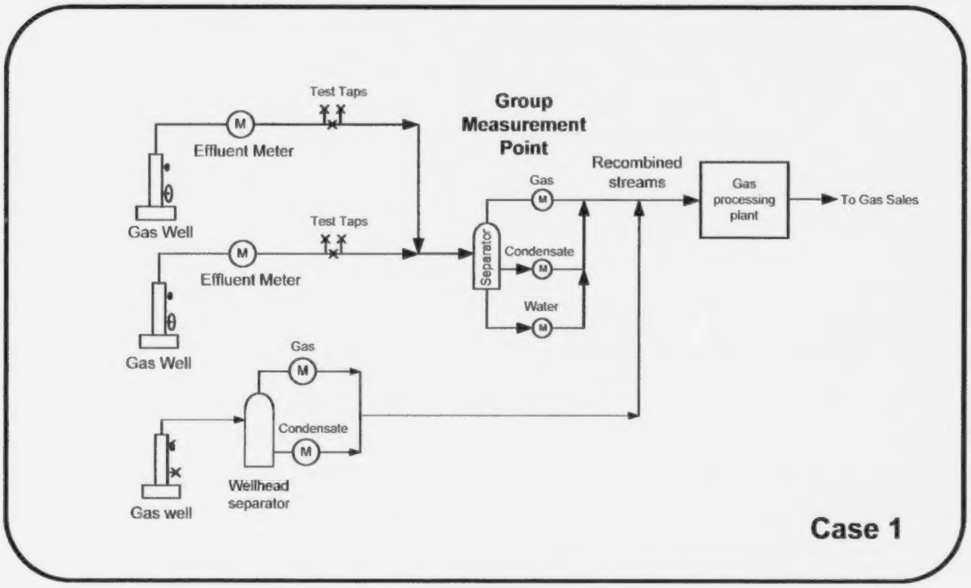
13.3 Reporting Scenarios

Gas Wells Producing Condensate

Condensate is associated with gas well production within gas facilities. If there is condensate, the total battery liquid volume must be measured.

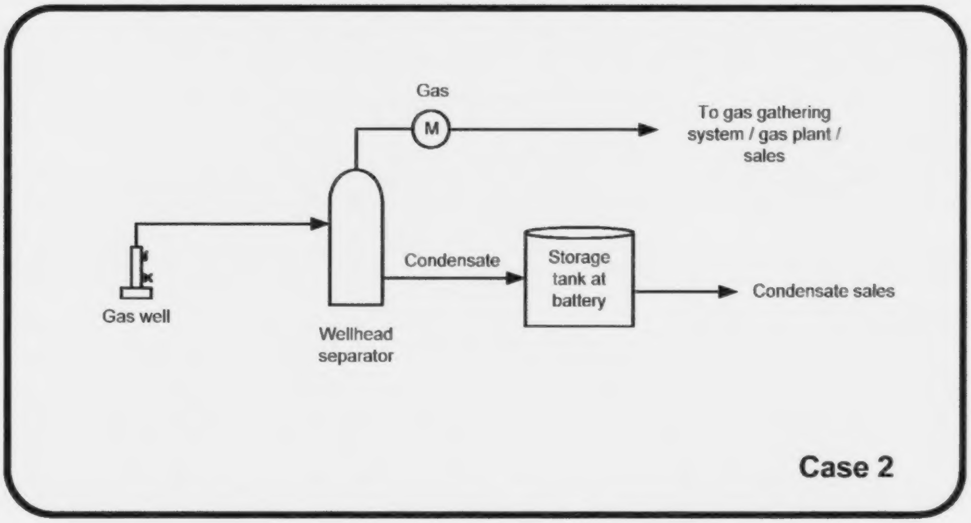
Case 1 (same as Case 6 in Alberta Energy *IL 87-3*)

Gas, condensate, and water being wet metered and tested or proration tested only, or separated from other well effluent, metered, commingled with gas (single well or multiwell group batteries) and sent to a gas plant for further processing must be converted to its GEV and added to the gas production for reporting purposes. The *NGRR* applies to this volume as part of the total production and disposition at the gas plant for Crown royalty.


Test Taps
M
Effluent Meter
Gas Well
Test Taps
M
Effluent Meter
Gas Well
Gas
M
Condensate
M
Wellhead separator
Gas well
Group Measurement Point
Gas
M
Separator
Condensate
M
Water
M
Recombined streams
Gas processing plant
To Gas Sales
Case 1

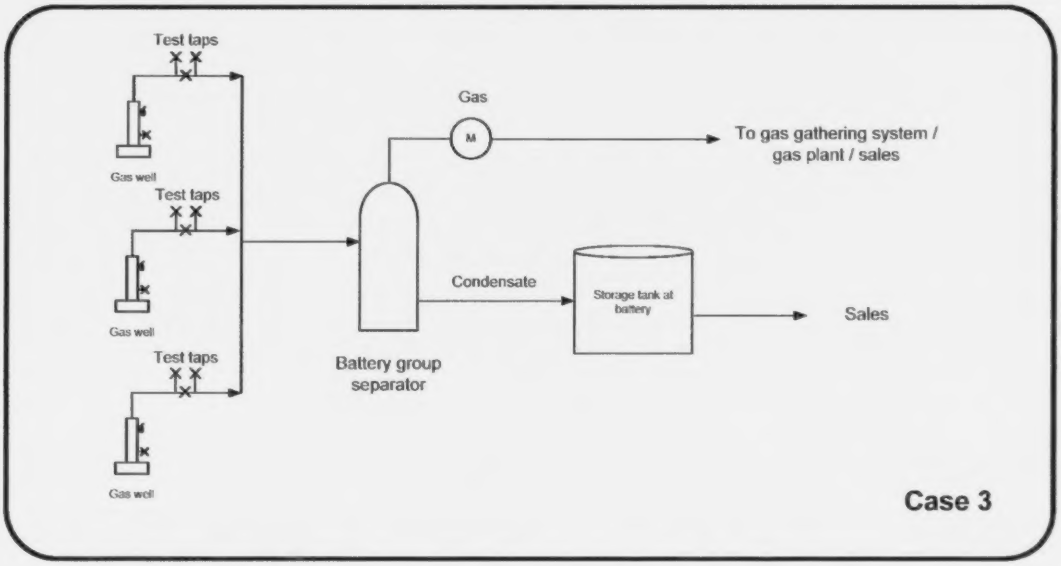
Case 2 (same as Case 7 in Alberta Energy *IL 87-3*)

Field condensate must be reported as a liquid production at the well if separated from well effluent, measured, and disposed of without further processing and before being delivered to a gas gathering system. The *NGRR* applies to this volume for Crown royalty.


Gas
M
To gas gathering system / gas plant / sales
Condensate
Storage tank at battery
Condensate sales
Gas well
Wellhead separator
Case 2

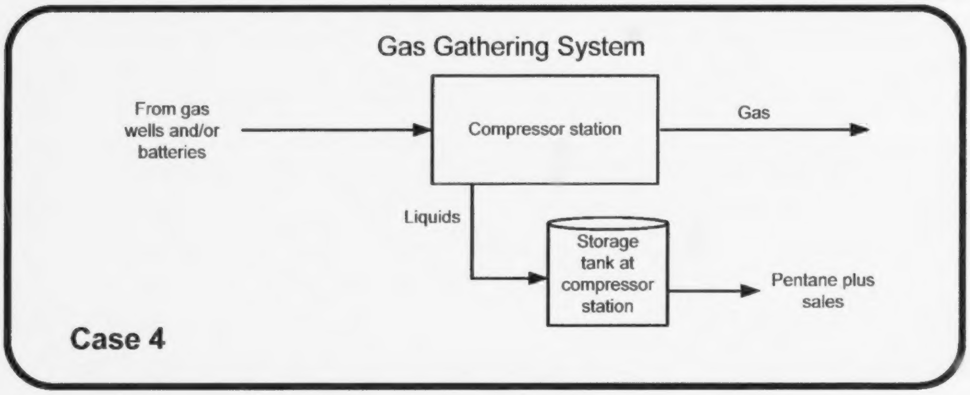
Case 3 (similar to Case 7 in Alberta Energy *IL 87-3*)

Field condensate must be reported as a liquid production at the well level if separated from multiwell gas proration or effluent proration batteries, measured, and disposed of from the group separator without further processing and before being delivered to a gas gathering system. The *NGRR* applies to this volume for Crown royalty.


Test taps
Gas well
Test taps
Gas well
Test taps
Gas well
Gas
M
To gas gathering system / gas plant / sales
Condensate
Storage tank at battery
Sales
Battery group separator
Case 3

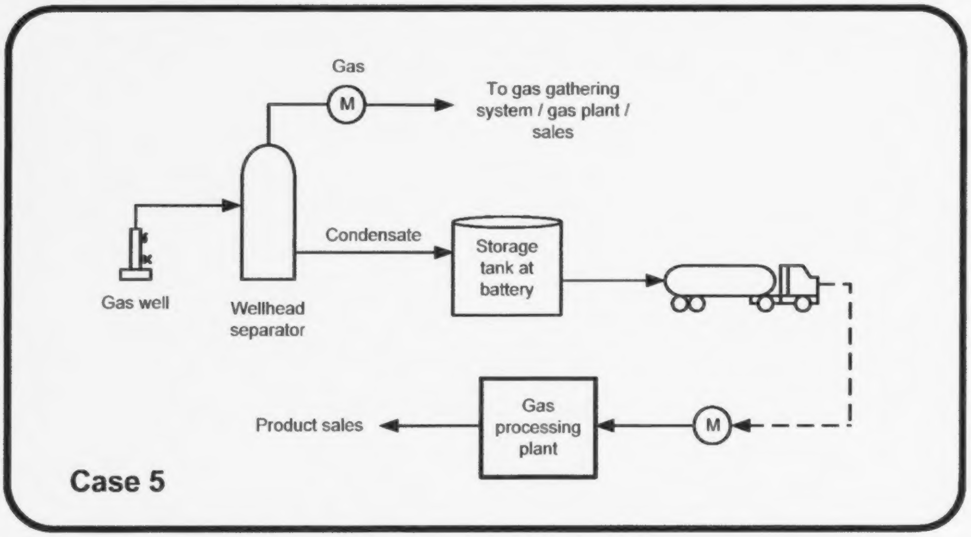
Case 4 (same as Case 8 in Alberta Energy *IL 87-3*)

Hydrocarbon liquid from one or more batteries recovered as a result of gas compression at a gas gathering system or a gas group battery and disposed of without further processing must be reported as pentanes plus liquid at the gas gathering system. The *NGRR* applies to this volume for Crown royalty.


Gas Gathering System
From gas wells and/or batteries
Compressor station
Gas
Liquids
Storage tank at compressor station
Pentane plus sales
Case 4

Case 5 (same as Case 9 in Alberta Energy *IL 87-3*)

Condensate separated from well effluent, measured, and trucked to a gas plant for processing must be converted to its GEV and added to the gas production for reporting purposes. The *NGRR* applies to this volume as part of the total production and sale at the gas plant. If there is no processing before sales, see Cases 2 and 3.


Gas
M
To gas gathering system / gas plant / sales
Condensate
Storage tank at battery
Gas well
Wellhead separator
Gas processing plant
M
Product sales
Case 5

14 Liquid Measurement

14.1 General Requirements

14.1.1 Scope

This section presents the requirements for liquid hydrocarbons measurement (i.e., crude oil, bitumen, condensate), liquefied petroleum gases (i.e., propane, butane), dense phase hydrocarbons (i.e., ethane, NGLs), and water.

14.1.2 Application of API Measurement Standards

For petroleum liquids, the API MPMS provides requirements for custody transfer measurement of hydrocarbons. For the purposes of this section, the degree of application of MPMS is determined by the level of uncertainty as required in Section 1.

14.1.3 System Design and Installation

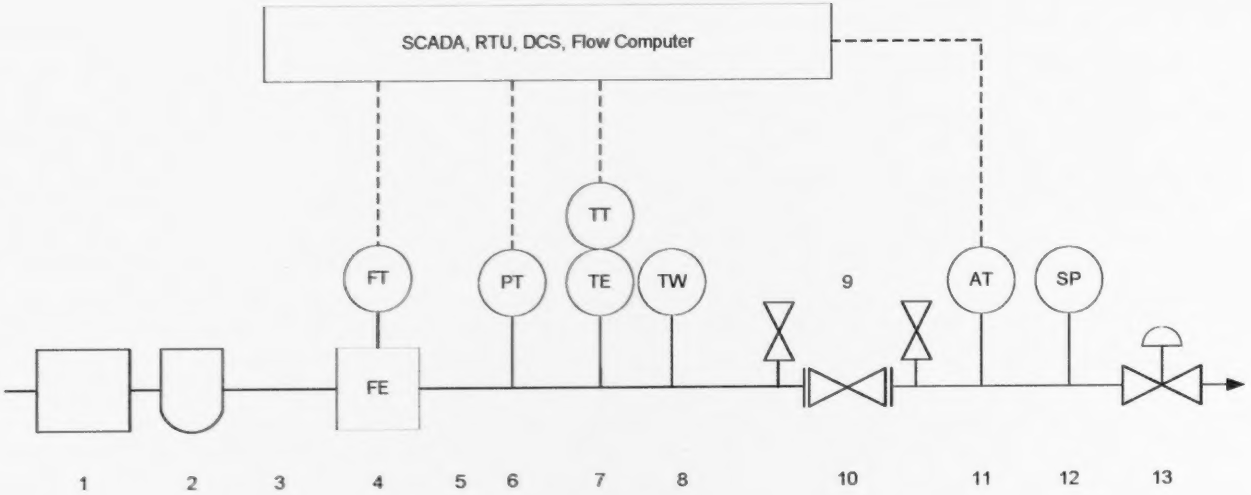
The meter system design must meet the overall system uncertainty requirements of Section 1. The ERCB considers a liquid measurement system to be compliant if the requirements in this section are met. Any EFM system designed and installed in accordance with API MPMS, Chapter 21.2, is considered to have met the audit trail and reporting requirements, but a performance evaluation is still required in accordance with Section 14.10 of this directive.

Liquid measurement systems typically consist of a primary measurement element, such as a meter; secondary measurement devices, such as temperature and pressure transmitters, and in some cases, differential pressure transmitters, level transmitters, and densitometers; and tertiary devices collectively termed electronic flow measurement (EFM) (e.g., distributed control system [DCS], supervisory control and data acquisition system [SCADA], and flow computers). In some cases, mechanical totalizers are used in place of EFM.

The meter and its associated peripheral equipment, such as strainers and air eliminators (where installed), proving valves, and piping must be designed and installed according to applicable industry accepted standards or the manufacturer's recommendations.

For delivery point applications where in-line proving is to be performed, proving taps and a double block and bleed divert valve must be installed. For positive displacement (PD) and coriolis meters, proving taps may be upstream or downstream of the meter if a ball prover, pipe prover, or master meter is used. For other types of linear meters or tank provers, the proving taps must be downstream of the meter (see Section 2.6).

Components of a liquid measurement system are shown in Figure 14.1.



Components

1) Strainer
2) Air eliminator
3) Upstream straight lengths
4) Meter
5) Downstream straight lengths
6) Pressure transmitter (if required)
7) Temperature transmitter
8) Check thermowell
9) Prover valves
10) Double block and bleed prover divert valve
11) Analyzer (e.g., water cut, densitometer)
12) Sample point (manual or on-line)
13) Flow control valve

Notes

1) Schematic is generic in nature and therefore all elements may not be required for a specific application or in that order. For example, for water meters, pressure and temperature transmitters for compensation to standard conditions are not normally required.
2) Air eliminator is mandatory for truck unloading applications but typically not required for pipeline applications.
3) Strainer required for most but not all meter types.
4) Upstream and downstream meter straight length requirement varies with meter type and upstream piping disturbances.
5) Flow transmitter (FT) may be close coupled to flow sensor (FE) or remote mounted.
6) Analyzers are typically water-cut monitors or densitometers.
7) Flow control valve may be upstream of prover taps for test separator applications.
8) No components such as analyzer fast loops or pressure relief valves should be between meter and prover taps.
9) Pressure relief valves should be located to preclude unmeasured fluids via a leaky relief valve.

Rev. 2

Figure 14.1. Typical liquid measurement system

14.2 Volume Measurement

14.2.1 Meter Selection

Appropriate engineering practice is required for selection of meter type and size. Specifically, parameters such as the following must be considered:

- process operating conditions (e.g., pressure, temperature, flow rate),
- fluid properties (viscosity, density, contaminants, bubble point),
- required accuracy to meet Section 1 uncertainty requirements,
- meter pressure drop,
- required straight lengths, and
- required back pressure.

Parameters known to vary with operating conditions, such as fluid properties (e.g., viscosity) and flow rate, should be considered for all operating scenarios (e.g., start-up, normal, and upset).

If meters are used for delivery point measurements, electronic temperature compensation is required. For existing mechanical automatic temperature compensated meters without gravity selection (ATC) or with gravity selection (ATG), see Section 10.3.1 for grandfathering criteria.

For meters to be proved using a conventional displacement prover (e.g., ball prover) or a captive displacer prover (piston and shaft), pulse outputs are required. For master meter proving, pulse outputs are recommended.

In addition to the meter selection parameters listed above, some upstream applications (e.g., propane sales loading rack at gas plants) may also have to meet Measurement Canada requirements.

There are two broad meter types, linear and differential (nonlinear) producer. The output of linear meters is proportional to flow rate. The output of differential producers is proportional to the flow rate squared. Table 14.1 lists various meter types for volume determination.

Table 14.1. Meter types

Linear meters	Nonlinear meters
Positive displacement	Orifice (see Section 4.3.1)
Turbine	Venturi
Vortex	Flow nozzle
Coriolis	Cone
Ultrasonic	Wedge
Magnetic (water or conductive fluids only)	Other differential devices

14.3 Shrinkage

For the purpose of this directive, "shrinkage" refers to a volume reduction associated with one or both of the following two processes:

1) blending of hydrocarbon streams of varying density (e.g., bitumen and condensate to reduce the viscosity of the bitumen for transport by pipeline), and/or
2) loss of volatile components through vapourization (e.g., flashing, weathering) due to a pressure reduction and/or temperature increase or to continued exposure to atmospheric conditions (e.g., conversion of live oil to stock tank conditions).

PRA-reported shrinkages other than the above and shrinkage or system loss/gains across facilities or pipeline system are outside the scope of this directive.

14.3.1 Live Oil Shrinkage

Until produced hydrocarbon fluids are stabilized, the oil is normally at its bubble point (equilibrium vapour pressure) condition due to the presence of volatile components. When the oil is discharged to a stock tank at atmospheric condition, the volatile components in the oil evaporate, causing a reduction in liquid volume. When live oils are metered (e.g., test separators), a shrinkage factor must be applied to correct the measured liquid volume from the metering pressure and temperature to stock tank conditions. When the meter is proved to stock tank conditions, the shrinkage factor is incorporated into the meter factor.

14.3.2 Hydrocarbon Blending and Flashing Shrinkages

When hydrocarbon molecules of different molecular sizes and intermolecular spacing (i.e., density) are mixed, the smaller molecules fill the spaces between the larger molecules. This results in a volume reduction from the arithmetic sum of the volumes of the blend components. The magnitude of this volume reduction is a function of the relative density and volumes of the hydrocarbon blend components. Calculation of shrinkage factors resulting from hydrocarbon blending without flashing must be performed in accordance with API MPMS, Chapter 12.3, or an equivalent industry accepted practice.

In some cases, volume reduction is a combination of the effects of loss of volatile components and intermolecular spacing. For example, blending of condensate or diluent with heavy oil can occur at any point in the production process. The condensate can be introduced in the flow line from the well, at the inlet separator, at the treater, at the storage tank, or at any combination of the above. If condensate is blended with the oil prior to the treater, condensate flashing may also occur.

Blending shrinkage must be determined if the density difference between the hydrocarbon fluids exceeds 40.0 kg/m^3 and must be reported if the shrinkage volume causes the delivery point volume to shrink by more than 0.1% and more than the 0.1 m^3 reporting limit on the PRA. Flashing shrinkage must be determined if the added diluent volume is > 2.0 m^3/day and/or > 5.0% of total oil production (see Table 5.2 for details).

The blending and flashing shrinkage is to be reported as an "SHR" disposition of the facility, and the flashing shrinkage is to be reported as a GEV (ABGE) of diluent receipt (REC) into the facility. When reporting the shrinkage, either flashing or blending shrinkages must be applied to the diluent volume, and the (heavier) oil volume must not be reduced by the shrinkage.

14.3.3 Shrinkage Factor Determination

Live oil shrinkage with entrained gas must be determined by any one of the following techniques:

- process simulation software,
- manual sampling and laboratory procedure (see API MPMS, Chapter 20), or
- physically degassing the prover oil volumes during meter proving of live oils (see Section 2.7.1).

Calculation of shrinkage volumes or factors is most often used to mitigate safety and environmental concerns if the live oil volumes are measured at high pressures or if the live oil contains H_2S.

When the manual sampling and laboratory method is used, the shrinkage factor must be based on analysis of a sample of the fluid taken at normal operating conditions. Shrinkage factors must be determined at either a well or battery level. The frequency of shrinkage factor determination should reflect changes in reservoir or operating conditions. Whenever the operating conditions change to a degree that could significantly affect the shrinkage factor, a new shrinkage factor must be determined based upon analysis of a sample of the fluid taken at the new operating conditions.

14.3.4 Shrinkage Factor Application

Shrinkage factors must be applied by being

- incorporated into a meter factor by degassing during proving, or
- incorporated into a meter factor by adjusting the meter factor numerically based on a shrinkage factor determined by process simulation or sampling/analysis, or
- applied to metered volumes after they are adjusted by the meter factor.

Caution is required to ensure that shrinkage is not applied more than once (e.g., degassing during meter proving and then applying it again as a factor to measured volumes).

14.4 Temperature Measurement

Temperature effects can increase the uncertainty associated with liquid hydrocarbon and water measurements. The magnitude of the effect of temperature measurement errors increases with decreasing hydrocarbon density as illustrated in Table 14.2.

Table 14.2. Temperature measurement error impact

Fluid	Approximate error per 1°C temperature measurement error (%)
Propane (510 kg/m^3@15°C)	0.29
Butane (600 kg/m^3@15°C)	0.18
Condensate (700 kg/m^3@15°C)	0.12
Crude oil (820 kg/m^3@15°C)	0.09
Crude oil (920 kg/m^3@15°C)	0.07
Water	0.02

Therefore, temperature compensation of measured volumes must be provided as required to meet the uncertainty requirements detailed in Section 1 and the requirements of this section. This applies to delivery point measurement, provers, and others (e.g., LACT) that require temperature compensation for volumetric determination.

Thermowells or direct insertion temperature elements must be used for all temperature measurements. Pipe or meter body skin temperature measurements, such as those used by coriolis meter, are not acceptable unless proven to be within the uncertainty requirements.

Thermowells must be installed in such a manner to be representative of the fluid temperature. Thermowells must not be installed in sections of piping where flow may not be present (e.g., dead-ended piping) or in a storage tank above the normal liquid level.

With the exception of coriolis or PD meters, thermowells must be installed 5 to 10 pipe diameters (D) downstream of the meter. For coriolis or PD meters, thermowells must be installed within 10 pipe diameters upstream or downstream of the meter. Valves or pipe restrictions must not be present between the thermowell and the meter's primary measurement element. Meter runs designed for trucked liquid measurement with the existing thermowell(s) within 20 D of the meter are grandfathered for the existing location and usage. If the meter run is modified or relocated, then the above requirements must be met.

Resistance temperature devices (RTD) are the preferred temperature measurement element. Other types of temperature measurement elements, such as thermocouples and thermisters, are acceptable provided that uncertainty requirements are met. Dial thermometers are not acceptable for pipeline-based delivery point measurement.

For pipelined delivery point measurements, two thermowells should be provided (i.e., one for measurement, one for verification).

Mechanical temperature compensators are not acceptable for new installations. For existing installations (installed before February 2, 2009), mechanical temperature compensators are acceptable if the operator can show that the uncertainty requirements of Section 1 are met (also see Section 10.3.2).

Temperature measurement type, tolerances, and calibration frequency are detailed in Table 14.3.

Table 14.3. Temperature measurement type, calibration frequency, resolution, and calibration tolerances

Application	Temperature measurement type[1]	Minimum resolution (°C)	Maximum calibration tolerance (°C)	Verification frequency
Delivery point with meter	Continuous with EFM	0.1	±0.5	Monthly[2]
Well oil (proration battery)	Composite meter factor or continuous with EFM	0.5	±1.0	Annual
Plant inlet or total battery/group condensate (gas gathering system)	Continuous or composite meter factor (see Section 14.9)	0.5	±1.0	Semiannual
Delivery point batch volumes into a pipeline or receipt at a battery/facility using tank gauging	One reading per load	0.1	±0.5	Semiannual

[1] For mechanical ATCs, see Section 10.3.2.

[2] Calibration frequency may be changed to bimonthly if three consecutive verification periods pass without the error exceeding the tolerance.

14.5 Pressure Measurement

Pressure compensation of hydrocarbon liquids is required where the meter pressure is above the base pressure for delivery point measurement unless the meter is proved to stock tank conditions. The pressure correction (Correction for the effect of Pressure on Liquids [CPL]) factor must be determined in accordance with API MPMS, Chapter 11.

Continuous pressure measurements and pressure compensation must be installed where required to meet Section 1 uncertainty requirements.

Pressure transmitters and gauges must be installed in accordance with applicable industry standards or manufacturer's recommendations typically 5 to 10 pipe diameters downstream of the meter.

14.6 Density Determination

Density may be measured manually from a sample or continuously using either a densitometer or a coriolis meter. Where manual density is used, the manual density value may be derived from a representative grab or composite sample and a laboratory density determination. Whichever method is used, the derivation of the value must be documented and meet the uncertainty requirement.

Continuous density measurements must be provided for mass measurement or if the variability in density is such that use of a fixed density value for temperature compensation would preclude meeting the uncertainty requirements.

On-line densitometers must be installed in accordance with applicable industry standards or manufacturer's recommendations, typically 5 to 10 pipe diameters downstream of linear meters, or a Coriolis meter may be used. If a densitometer is used as part of a mass measurement system (e.g., ethane, NGLs), it must be installed in accordance with API MPMS, Chapter 14.6.

Laboratory density determination may be performed using either the hydrometer methods (see API MPMS, Chapter 9) or the precision densitometer method (ASTM D4052). If practical, densitometer measurements should be made at 15°C to preclude the requirement for temperature compensation. If this is not practical (e.g., viscous heavy oil applications) or when using a hydrometer, manual temperature compensation must be provided using the appropriate API MPMS table (see Section 14.9).

14.7 Tank Measurement

Tanks in this section refer to storage tanks that are open to atmosphere, tanks with and without floating roofs, and tanks with blanket gas, as well as bullets and other pressurized storage vessels. The use of tanks open to atmosphere should be limited to liquids with a Reid Vapour Pressure specification of <103 kPa.

Volumetric measurement using storage tanks is based upon a level measurement used in conjunction with a strapping table.

Provided that Section 1 uncertainty tolerances are met, the licensee may use storage tanks for determination of inventory, well test, or delivery point volume measurements. The licensee must ensure that the tank diameter, gauging equipment (e.g., gauge tape or automatic tank gauge), gauging procedures, and tank strapping table are appropriate for the tank and product being gauged and are capable of achieving the required uncertainty.

Manual gauge boards and automatic tank gauges must be designed, installed, and operated in accordance with manufacturer's specifications and recommendations and must be maintained in good working order.

14.7.1 Tank Strapping

Tank strapping tables convert (i.e., relate) level to indicated volume.

Depending upon the uncertainty required, tank strapping tables may be prepared using either engineering calculations based upon approximate tank dimensions or via the tank strapping procedures detailed in API MPMS, Chapter 2.

14.7.2 Tank Sizing

The relative error of the level measurement is determined by the absolute error of the level measurement relative to the level measured. The level measured or change in level is in turn determined by the diameter of the tank and transaction size. To improve uncertainty, one can measure the level more accurately or increase the level change measured by changing the ratio of tank height to diameter or by increasing the size of the transaction (delivery point) or test volume compared to the overall tank height.

Tank sizing must address the intended use (e.g., delivery point or well test), level measurement technique (e.g., gauge board, hand dip, radar gauge), and well test or transaction volume.

Knowing the transaction or test volume, one can determine tank diameter as follows:

$$d \leq (V/a)^{1/2}$$

Knowing the tank diameter, one can determine minimum transaction or test volume as follows:

$$V \geq a \times d^2$$

Where:

V = test fluid volume or delivery point batch volume in m^3
d = tank diameter in metres
a = accuracy coefficient

The accuracy coefficients for conventional crude oil applications are

$a = 0.39$ for all test fluid volumes
$a = 0.39$ for delivery point batch volumes ≤ 100 m^3/d
$a = 0.92$ for delivery point batch volumes >100 m^3/d

The accuracy coefficients for heavy crude oil applications are

$a = 0.39$ for treatment facility receipt batch volumes
$a = 0.92$ for sales/delivery point batch volumes
$a = 1.6$ for primary heavy oil test fluid volumes

14.7.3 Manual Tank Gauging

Manual tank gauging can be accomplished using tank dips or a gauge board.

Gauge boards are acceptable for test tanks and inventory measurements but not for delivery point measurements. See Table 14.4 for marking gradations.

Gauge tapes must have a minimum resolution of 3 mm.

Table 14.4. Gauge board marking gradations

Gauge board application	Maximum marking separation (mm)
Conventional oil testing	25
Heavy oil / crude bitumen testing	60
Inventory	150

If safe work conditions permit, gauge boards should be read at eye level.
Calibration of gauge boards is not required.

14.7.4 Automatic/Electronic Tank Gauging

Electronic tank gauges must have a minimum resolution of 3 mm. One reading of the instrument is acceptable.

Instruments must be calibrated in accordance with the manufacturer's recommendation or at a minimum annually.

14.7.5 Tank Gauging Applications

Inventory Tank Gauging

For monthly inventory measurement gauging, one reading of the gauge tape, gauge board, or automatic tank gauge is acceptable. Levels must be reported to the nearest 75 mm.

The tank does not need to be stabilized or isolated for inventory measurements.

Test Tank Gauging

For gauge measurement on test tanks, one reading of the gauge board or automatic tank gauge is acceptable at the start and end of the test.

Levels are reported to the nearest 10 mm.

Delivery Point Measurement

When tank gauging is used to determine an oil/emulsion volume, the gauging procedures must be conducted in accordance with the following:

- The licensee must ensure that the strapping table has been prepared in accordance with API MPMS, Chapter 2.
- The licensee must ensure that the tank level is not changing or is stabilized when the gauge readings are taken. This often requires isolating or shutting in the tank before gauging.
- All gauge tapes and electronic level devices must have a minimum resolution of 3 mm.
- Manual tank dips are performed in accordance with API MPMS, Chapter 3.1A. For tanks with a nominal capacity greater than 160 m^3, two consecutive readings within 10 mm of each other are required. The two readings are averaged. For tanks with a nominal capacity of 160 m^3 or less, one reading is acceptable.
- Automatic tank gauging is performed in accordance with API MPMS, Chapter 3.1B.

- Temperature measurements are performed in accordance with API MPMS, Chapter 7.
- Gauge boards must not be used for delivery point measurement.

14.8 Sampling and Analysis

Sampling and analysis must be in accordance with Sections 6, 8, and 10 or other equivalent industry standard methods.

14.8.1 Fluid Sampling Requirements for S&W and Density Determination

S&W determination procedure including the frequency of sampling must be representative of the entire volume transaction as well as the subsequent S&W sample analysis. There are two methods to obtain this measurement: sampling or on-line analysis using a suitable instrument (water-cut analyzer or product analyzer). Sampling can be categorized by two methods: spot/grab sampling or continuous proportional sampling. It is important that the sample location be carefully selected such that the flowing stream is adequately mixed. This can be achieved by

- installing in-line mixers,
- selecting a sampling point that offers the most practical location for collecting a sample that is mixed, such as after valves, elbows, and reducers,
- selecting a sampling point that is downstream of a metering point because of the piping elements associated with a meter run, or
- collecting samples from a number of different locations, analyzing them, and making a selection based on the location that provides the most consistent and reasonable analysis.

Grab or spot sampling may be used if the water cut is below 10% for proration oil testing. Otherwise continuous proportional sampling or the use of a product analyzer is required.

Water-cut analyzers operate on a number of different principles and often are best suited for specific applications. Analyzers must be installed and maintained in accordance with the manufacturer's recommendations.

For a single-well battery or a multiwell group battery, trucking emulsion off-site, the volumes will be determined by the receiving facilities.

For single-well oil batteries with two-phase or three-phase separators delivering produced oil/emulsions by pipeline to another battery, the sample must be taken at or near the oil/emulsion meter using a continuous proportional sampler. An on-line product analyzer is also acceptable for the determination of water cut (see Section 15.2.2.1 for the exception). This is a measurement-by-difference situation at the receiving battery/facility (see Section 5.5).

For an oil battery with emulsion tanks, the oil and water inventory volumes in the emulsion tanks may be determined by one of the following methods:

- taking a spot (grab) sample anywhere between the wellhead or separator and the tank and applying the percentage of sediments and water (%S&W) to the tank inventory,
- using water-indicating paste on the gauge tape to determine the water/oil interface in the tank inventory,
- using a representative thief sample taken from the tank,

- taking the average %S&W of the total battery production and applying that to the tank inventory,
- using the average %S&W of the trucked out volumes, or
- deeming the tank inventory to be entirely oil and making changes/amendments based on delivery volumes.

14.8.2 S&W Determination

The licensee must select the most appropriate method for determining the %S&W. There are three static analysis methods of the sampled fluid generally considered acceptable by the ERCB based on the %S&W:

1) the centrifuge or Karl Fischer method (combined with separate method for sediment determination) for water cuts between 0 and 10%,
2) the graduated cylinder method of a larger sample for water cuts between 10 and 80% and centrifuging the oil emulsion portion, and
3) the graduated cylinder method of a larger sample for water cuts between 80 and 100% and not centrifuging the oil emulsion portion.

Recommended procedures for these three methods are shown in Appendix 4. Any alternative methods must be supported by testing that shows representative results are achieved and these alternative procedures must be made available to the ERCB upon request.

In some instances it is possible to use a computer algorithm to determine the oil and water volumes in the emulsion based on the measured densities of the emulsion and the known densities of the oil and water components of the emulsion. The oil and water base densities must be based on an analysis of the actual oil and water production being measured and must be corrected for the temperature at which the emulsion density is measured. Temperature correction for produced water density should be calculated in accordance with API MPMS, Chapter 20.1.

14.9 Liquid Volume Calculations

Liquid volume measurements must be determined to a minimum of two decimal places and rounded to one decimal place for monthly reporting in cubic metres. If there is more than one volume determination within the month at a reporting point, the volumes determined to a minimum of two decimal places must be totalled prior to the total being rounded to one decimal place for PRA reporting purposes.

Standard or base conditions for use in calculating and reporting liquid volumes are 15°C and 0 kPa gauge or the equilibrium vapour pressure at 15°C (whichever is higher).

The liquid volume calculations must adhere to the following:

1) Total indicated volume for the transaction period (daily, weekly, monthly) is measured and recorded. This applies to measurement by meter, weigh scale, or tank gauging.
2) The volumetric meter factor for the flow meter is applied to the total indicated volume.

3) For oil, the percentage of water in the gross volume is determined by measuring the %S&W of a representative sample or by continuous on-line measurement. The result is a quantified volume of oil and of water.

4) For oil, a shrinkage factor is applied to the volume in order to determine the volume at stock tank conditions (atmospheric pressure). Some applications may already have the shrinkage factor incorporated into the meter factor.

5) Where required, compensation for the effects of pressure and temperature on the liquid must be applied.

6) Composite meter factors that include temperature correction factors (CTL) must not be used for delivery point measurement. However, they are acceptable for other applications, such as test meters, inlet meters, and water meters, provided that the variability of parameters affecting meter performance such as operating temperature, fluid viscosity, and fluid composition is such that the net effect is within the uncertainty requirements for the application.

14.9.1 General Equations for Determining Liquid Volumes at Base Conditions

14.9.1.1 Linear Meters

Indicated Volume

IV = closing reading – opening reading

or

IV = (closing pulses – opening pulses) / KF

Gross Standard Volume

$\text{GSV} = \text{IV} \times \text{CTL} \times \text{CPL} \times \text{MF}$ or

$\text{GSV} = \text{IV} \times \text{CMF}$ or

$\text{GSV} = \text{IV} \times \text{MF} \times \text{DEN}_{\text{obs}} / \text{DEN}_{\text{b}}$ or

$\text{GSV} = \text{Mass} / \text{DEN}_{\text{b}}$

Net Standard Volume

$\text{CSW} = 1 - (\%\text{S\&W} / 100)$

$\text{NSV} = \text{GSV} \times \text{CSW} \times \text{SF}$

SF = Shrinkage Factor

Water Cut

$\text{DEN}_{\text{obs,o}} = \text{DEN}_{\text{b,o}} \times \text{CTL}_{\text{o}}$

$\text{DEN}_{\text{obs,w}} = \text{DEN}_{\text{b,w}} \times \text{CTL}_{\text{w}}$

$\text{Water Cut} = (\text{DEN}_{\text{obs,e}} - \text{DEN}_{\text{obs,o}}) / (\text{DEN}_{\text{obs,w}} - \text{DEN}_{\text{obs,o}})$

Definitions

CMF – Composite Meter Factor: A meter factor that includes corrections for the effects of any combination of temperature, pressure, or shrinkage.

CPL – Correction for the effect of Pressure on Liquid: Correction for compressibility of liquid at normal operating conditions.

CTL – Correction for the effect of Temperature on Liquid: Correction for effect of temperature on liquid at normal operating conditions.

CTL_o – Correction for the effect of Temperature on Oil: Correction for effect of temperature on oil at normal operating conditions.

CTL_w – Correction for the effect of Temperature on Water: Correction for effect of temperature on water at normal operating conditions.

CSW – Correction for Sediment and Water: Correction for sediment and water to adjust the gross standard volume of the liquid for these nonmerchantable items.

DEN_b – Base Density: Liquid density in kilograms per cubic metre at base pressure and temperature.

$DEN_{b,o}$ – Base Density – Oil: Liquid density of oil in kilograms per cubic metre at base pressure and temperature.

$DEN_{b,w}$ – Base Density – Water: Liquid density of water in kilograms per cubic metre at base pressure and temperature.

DEN_{obs} – Observed Density: Liquid density in kilograms per cubic metre at observed pressure and temperature.

$DEN_{obs,o}$ – Observed Density – Oil: Oil density in kilograms per cubic metre at observed pressure and temperature.

$DEN_{obs,w}$ – Observed Density – Water: Water density in kilograms per cubic metre at observed pressure and temperature.

GSV – Gross Standard Volume: The volume at base conditions corrected also for the metre's performance (MF or CMF).

IV – Indicated Volume: The change in meter reading that occurs during a receipt or delivery.

KF – k-factor: A term in pulses per unit volume determined during a factory or field proving. The number of pulses generated by a linear meter divided by the k-factor will determine the indicated volume.

MF – Meter Factor: A dimensionless term obtained by dividing the volume of the liquid passed through the prover corrected to standard conditions during proving by the indicated standard volume (ISVm) as registered by the meter.

NSV – Net Standard Volume: The gross standard volume corrected for shrinkage and nonmerchantable quantities such as sediment and water.

Composite Meter Factors

A CMF is a meter factor that includes corrections for the effects of any combination of temperature, pressure, or shrinkage.

A CMF may be used

- if anticipated changes in pressure and temperature parameters result in uncertainties within those stated in Section 1,
- for test separators at oil batteries, and
- for separators at gas wells.

Test separators typically use CMFs to apply temperature correction where an EFM system is not used. The CMF can also include correction for shrinkage. The operator must ensure that corrections included in CMFs are not being applied elsewhere, such as in a SCADA system or field data capture system.

Note that in separator applications where the hydrocarbon liquid is at its equilibrium vapour pressure, CPL is 1.0 and therefore is not required to be calculated as part of a CMF.

Calculation example for volumetric proving at an oil test separator:

$CMF_T = IV_P \times CTL_P / IV_M$

CMF_T = CMF that includes correction for the effect of temperature (CTL)
IV_P = Indicated prover volume
CTL_P = CTL calculated using prover temperature during run
IV_M = Indicated meter volume

If the indicated volume of the prover is recorded after degassing, the CMF will include correction for shrinkage (CMF_{TS}).

14.9.1.2 Orifice Meters

While not as common, orifice meters can be used for liquid measurement. For these applications, either of the following equations must be used.

API MPMS 14.3.1 (AGA-3):

$$Q_b = \frac{Q_m}{\rho_b} = \frac{N_1 C_d E_v Y d^2 \sqrt{\rho_f \Delta P}}{\rho_b}$$

API MPMS 14.8 (Natural Gas Fluids Measurement – Liquefied Petroleum Gas Measurement):

$$Q_b = N_1 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{\rho_f}} \left(C_{tl} C_{pl} \right)$$

Where:

N_1	Unit conversion factor (0.0000351241 when using SI units listed below)
C_d	Orifice plate coefficient of discharge
E_v	Velocity of approach factor

Y	Expansion factor
d	Orifice plate bore diameter calculated at flowing temperature (mm)
ΔP	Orifice differential pressure (kPa)
ρ_f	Density of the liquid at flowing conditions (kg/m^3)
ρ_b	Density of the liquid at base conditions (kg/m^3)
Q_b	Volume flow rate at base conditions (m^3/sec)
Q_m	Mass (kg)
C_{tl}	Compensation factor for the effect of temperature on liquid
C_{pl}	Compensation factor for the effect of pressure on liquid

For other nonlinear meters, refer to the applicable industry standard or manufacturer's documentation for determining base volumes.

14.9.1.3 Pressure and Temperature Compensation

Standards for Calculation

CTL and CPL must be calculated as per the current standards in Table 14.5 for the applicable density and temperature range. Applications using the superseded standards below that were in use prior to the implementation of these standards (April 18, 2011) do not require upgrading. Calculations for determining CTL or CPL not listed in Table 14.5 are not acceptable.

Table 14.5. Pressure and temperature compensation standards*

Standard	Product and density range	Calculation input(s)	Calculation output(s)	Comments
API MPMS 11.1 May 2004	Crude oil, refined products, and lubricating oils 611.16 – 1163.85 kg/m^3	Observed density Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	Density @ 15°C CTL CPL VCF	Current
API MPMS 11.2.2M 1986	Hydrocarbon liquid 350 – 637 kg/m^3	Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	CPL	Current
API MPMS 11.2.4 GPA TP-27 Table 53E September 2007	NGL and LPG 210 – 740 kg/m^3	Observed density Observed temperature	Density @ 15°C	Current

(continued)

Standard	Product and density range	Calculation input(s)	Calculation output(s)	Comments
API MPMS 11.2.4 GPA TP-27 Table 54E September 2007	NGL and LPG 351.7 – 687.8 kg/m^3	Density @ 15°C Flowing temperature	CTL	Current
API MPMS 11.1 (formerly API 2540) Table 53A 1980	Crude oil 610 – 1075 kg/m^3	Observed density Observed temperature	Density @ 15°C	Superseded by API MPMS 11.1 2004
API MPMS 11.1 (formerly API 2540) Table 54A 1980	Crude oil 610 – 1075 kg/m^3	Density @ 15°C Flowing temperature	CTL	Superseded by API MPMS 11.1 2004
API MPMS 11.1 (formerly API 2540) Table 53B 1980	Generalized products 610 – 1075 kg/m^3	Observed density Observed temperature	Density @ 15°C	Superseded by API MPMS 11.1 2004
API MPMS 11.1 (formerly API 2540) Table 54B 1980	Generalized products 610 – 1075 kg/m^3	Density @ 15°C Flowing temperature	CTL	Superseded by API MPMS 11.1 2004
ASTM-IP-API Petroleum measurement tables for light hydrocarbons Table 53 1986	Light hydrocarbon liquid 500 – 653 kg/m^3	Observed density Observed temperature	Density @ 15°C	Superseded by API MPMS 11.2.4/ GPA TP-27 September 2007
ASTM-IP-API Petroleum measurement tables for light hydrocarbons Table 54 1986	Light hydrocarbon liquid 500 – 653 kg/m^3	Density @ 15°C Flowing temperature	CTL	Superseded by API MPMS 11.2.4/ GPA TP-27 September 2007
API MPMS 11.2.1M 1984	Hydrocarbon liquid 638 – 1074 kg/m^3	Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	CPL	Superseded by API MPMS 11.1 2004

[*] Note: The printed API MPMS, Chapter 11.1, Tables 53, 53A, and 53B include correction for the thermal expansion or contraction of a glass hydrometer. Existing computer implementations of these tables may or may not include hydrometer correction.

14.10 Electronic Flow Measurement for Liquid Systems

An EFM is any flow measurement and related system that collects data and performs flow calculations electronically. If it is part of a DCS, SCADA, or Programmable Logic Controller system (PLC), only the EFM portion has to meet the requirements in this section.

The following systems are not defined as an EFM:

- any meter with an electronic totalizer or pulse counter that does not perform flow calculations (with or without built-in temperature compensation), and

- a remote terminal unit (RTU) that transmits any data other than flow data and does not calculate flow.

Hardware and software requirements:

- The EFM data storage capability must exceed the time period used for data transfer from the EFM.
- The EFM must be provided with the capability to retain data in the event of a power failure (e.g., battery backup, UPS, EPROM).
- The system must have appropriate levels of access for security, with the highest level of access to the system restricted to authorized personnel.
- The EFM must be set to alarm on out-of-range inputs, such as temperature, pressure, differential pressure (if applicable), flow, low power, or communication failures.
- Any EFM configuration changes or forced inputs that affect measurement computations must be documented through either electronic audit trails or paper records.
- The values calculated from forced data must be identified as such.

14.10.1 Performance Evaluation

If an EFM is used to calculate net liquid volumes, the licensee must be able to verify that it is performing within the ERCB target limits defined in this section.

A performance evaluation test must be completed within **two weeks** after the EFM is put into service and **immediately** after any change to the computer algorithms that affects the flow calculation, and it must be documented for ERCB audit upon request. For existing EFM systems, the licensee should conduct its own performance evaluations to ensure that they are performing adequately. A performance evaluation must be conducted and submitted for ERCB audit on request. The ERCB considers either one of the following methods acceptable for performance evaluation.

- A performance evaluation test conducted on the system by inputting known values of flow parameters into the EFM to verify the volume calculation and other parameters. The test cases included in this section (Tables 14.6 to 14.9) are for liquid meters each with different flow conditions.

  Test cases 1 to 5 for each liquid type are for density correction from flowing temperature to 15°C. The hydrometer correction is used to compensate for the glass expansion when used to measure the density.

  Test cases 6 to 10 for each liquid type are for volume correction using CPL and/or CTL factors to correct to base conditions. Other manufacturer's recommended methodologies can also be used to evaluate the EFM performance, provided that the volumes obtained from a performance evaluation test agree to within ±0.1% of those recorded on the sample test cases.

- Evaluation of the EFM calculation accuracy with a flow calculation checking program that performs within the target limits for all the factors and parameters listed in the test cases below. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information is to be taken from the EFM and input into the checking program. If the instantaneous EFM flow parameters, factors, and flow rates are not updated simultaneously, multiple snapshots may have to be taken to provide a representative evaluation.

The densities (test cases 1 to 5, 11 to 15) or volumes (test cases 6 to 10, 16 to 20) obtained from a performance evaluation test must agree to within ±0.1% of those recorded on the sample test cases. If the ±0.1% limit is exceeded, the EFM must be subjected to a detailed review of the calculation algorithm to resolve the deviation problem.

14.10.2 Test Cases for Verification of Oil Flow Calculation Programs

These test cases were calculated using the following standards.

Density @ 15°C / CTL / CPL / CTPL: API MPMS, Chapter 11.1: Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils (May 2004).

Hydrometer Correction: API MPMS, Chapter 9.3: Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method (November 2002).

14.10.3 Test Cases for Verification of NGL and LPG Flow Calculation Programs

These test cases were calculated using the following standards.

Density @ 15°C: API MPMS, Chapter 11.2.4 (GPA Technical Publication TP-27): Temperature Correction for the Volume of NGL and LPG, September 2007, Table 53E.

Hydrometer Correction: API MPMS, Chapter 9.3: Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method (November 2002).

CPL: API MPMS, Chapter 11.2.2M Compressibility Factors for Hydrocarbons, October 1986.

CTL: API MPMS, Chapter 11.2.4 (GPA Technical Publication TP-27): Temperature Correction for the Volume of NGL and LPG, September 2007, Table 54E.

Table 14.6. Oil density correction test cases—density correction to 15°C

	Inputs		Outputs	
Test case	Oil density @ observed temp. (kg/m³)	Observed temp. (°C)	Oil density corrected to 15°C (kg/m³) with hydrometer correction	Oil density corrected to 15°C (kg/m³) without hydrometer correction
1	875.5	120.0	942.9	945.0
2	693.0	11.4	689.9	689.8
3	644.0	84.45	704.7	705.7
4	625.5	53.05	660.8	661.4
5	779.0	25.0	786.7	786.8

Table 14.7. Volume correction test cases at atmospheric pressure—volume correction to 15°C and 0.0 kPa(g)

	Inputs				Outputs				
Test case	Metered volume (m^3)	Density (kg/m^3) @ 15°C	Observed temp. (°C)	Observed pressure (kPag)	CTL	CPL	CTL corrected volume (m^3)	CTL & CPL corrected volume (m^3)	CTL & CPL corrected volume (m^3) rounded*
6	60.0	903.5	40.5	700.0	0.98071	1.00050	58.842368	58.871812	58.9
7	15.0	779.0	3.9	400.0	1.01120	1.00034	15.167952	15.173133	15.2
8	100.0	1008.0	89.0	3700.0	0.95472	1.00255	95.472126	95.715578	95.7
9	250.0	875.5	5.0	200.0	1.00799	1.00013	251.998452	252.030396	252.0
10	150.0	640.0	75.0	1000.0	0.90802	1.00365	136.203308	136.700489	136.7

* The CPL and CTL shown are rounded to five decimal places, but they are not rounded prior to calculating the volumes. Only the final volume is rounded to one decimal place to meet reporting requirements. The corrected volumes are shown to six decimal places for verification purposes.

Table 14.8. Other liquid hydrocarbon density correction test cases—density correction to 15°C

	Inputs		Outputs	
Test case	Liquid density @ observed temperature and base pressure (kg/m^3)	Observed temperature (°C)	Liquid density corrected to 15°C (kg/m^3) with hydrometer correction	Liquid density corrected to 15°C (kg/m^3) without hydrometer correction
11	525	92.5	614.2	614.9
12	412.5	11.4	404.5	404.5
13	355.5	84.45	506.7	506.9
14	623.5	53.05	658.1	658.7
15	652.5	25	661.3	661.5

Table 14.9. Volume correction test cases at equilibrium vapour pressure—volume correction to 15°C and equilibrium vapour pressure

	Inputs					Outputs				
Test case	Metered volume (m^3)	Density (kg/m^3) @ 15°C and EVP	Observed temp. (°C)	Observed pressure (kPag)	Equilibrium vapour pressure (kPa) @ observed temp.	CTL	CPL	CTL corrected volume (m^3)	CTL & CPL corrected volume (m^3)	CTPL corrected volume (m^3) rounded*
16	60.0	544.5	40.5	1645.0	738.0	0.93642	1.0054	56.184942	56.488356	56.5
17	15.0	402.0	3.9	1125.0	1125.0	1.05931	1.0000	15.889672	15.889672	15.9
18	100.0	632.0	55.0	348.0	213.0	0.93587	1.0004	93.586521	93.623473	93.6
19	250.0	512.5	5.0	1500.0	494.0	1.02732	1.0041	256.830532	257.880793	257.9
20	150.0	356.5	-14.5	4260.0	1650.0	1.20782	1.0224	181.173148	185.235683	185.2

* The CPL and CTL shown are rounded as per their respective standards. CPL is rounded to four decimal places and CTL to five decimal places. They are not rounded prior to calculating the volumes. Only the final volume is rounded to one decimal place to meet reporting requirements. The corrected volumes are shown to six decimal places for verification purposes.

14.11 Records

For all metering equipment covered by this section, records must be kept as outlined in the following report types and made available for examination by the ERCB. Operators are given flexibility in the formatting of these reports; it is not necessary to present the information exactly as outlined.

These records must be maintained for mechanical, electromechanical, or EFM. EFM systems may retain this information automatically. It is the responsibility of the operating company to ensure that the records are saved for the required time, a minimum of 12 months. It is advisable to save the records on a regular basis and when metering problems occur, so they are not lost when memory is full or when the EFM is shut off.

The reports must be recorded using electronic/magnetic (not necessarily on the EFM), printed, or handwritten media and retained for a minimum of 12 months. They must be produced upon request by the ERCB.

14.11.1 The Daily Report

The following information must be recorded on a daily or per test basis for test meters only:

- test meter and well identification
- test period accumulated flow
- hours on production or hours of flow (specify)

14.11.2 The Monthly Report

The monthly report is for the entire system, providing data for each measurement point. It is to contain the following at each measurement point as applicable:

- monthly cumulative flow
- indications of any change made to volumes, and supporting documentation
- total hours on production or hours of flow (specify) (for production or test meters only)

14.11.3 The Event Log

When any parameter that affects the flow calculation is changed, such as meter factor, fluid densities, or transmitter range, a process is required to record the change. In an EFM system this can be accomplished using the event log within the EFM (if so equipped). These parameter changes can also be recorded manually on paper or electronic records.

The event log must include items such as

- instrumentation range changes
- algorithm changes
- meter factor or k-factor changes
- orifice plate changes
- fixed fluid density changes
- other manual inputs

The log must identify the person making the change and the date of the change.

14.11.4 EFM Specific Reports

The following reports are required together with those in 14.11.1 and 14.11.3 where applicable.

14.11.5 The Daily Report

The following information must be recorded on a daily basis:

- meter identification
- daily accumulated flow
- hours on production or hours of flow (specify) (for production or test meters only)
- flow data audit trail—include at least one of the following:
  - instantaneous values for flow rate, operating pressure (if applicable), and temperature taken at the same time each day
  - daily volume and average daily values for operating pressure (if applicable) and temperature
  - hourly accumulated flow rate and average hourly values for operating pressure (if applicable) and temperature

14.11.6 The Meter Report

The meter report is primarily required to confirm that the EFM is operating properly. A meter report is not required when using mechanical or electromechanical systems, where many of these values are fixed. For these mechanical or electromechanical meters, records are required to verify that the various factors used in the calculation are correct.

The meter report details the configuration of each meter and flow calculation information. It must include the required parameters to demonstrate that the net standard volume is being properly computed from the gross indicated volume. The type of EFM device will determine which of the following are required:

- Instantaneous flow data
  - gross and net flow rate or gross and net volume calculated over a time period such that the correction factors are not changing
  - operating pressure
  - differential pressure (if applicable)
  - flowing temperature
  - flowing density
  - sediment and water content if an on-line S&W monitor is used
  - CTL
  - CPL
  - CTPL

- Current configuration information
  - meter identification
  - date and time
  - pressure base
  - temperature base
  - flowing or base density if a fixed density is used
  - meter factor and/or k-factor
  - shrinkage factor (where applicable)

14.11.7 The Alarm Log

The alarm log includes any alarms that may have an effect on the measurement accuracy of the system. The time of each alarm condition and the time each alarm is cleared must be recorded. The alarm log includes items such as

- master terminal unit failures
- remote terminal unit failures
- communication failures
- low-power warning
- high/low volumetric flow rate
- overranging of end devices

15 Water Measurement

This section presents the requirements for measurement and reporting of water from oil and gas production, water source, water injection and disposal, waste processing and disposal, storage and disposal cavern, and thermal in situ oil sands schemes.

All liquid water produced at wellhead or group separator conditions (Product: WATER) is considered production and must be reported to the PRA. Water that is in the vapour phase under these separator conditions must not be reported as production even if it drops out later in the gas system (see Section 15.2.1.6). Reported water volumes must be corrected to 15°C when so stipulated in this directive. All sample analyses, test data, and test date records must be submitted to the ERCB upon request.

For the purpose of this directive, water from a saline water source is considered as brackish (Product: BRKWTR) and water from a nonsaline water source (with total dissolved solids [TDS] less than 4000 milligrams per litre [mg/L]) is considered as fresh (Product: FSHWTR). Production of nonsaline water may require a groundwater diversion permit under the Alberta Environment and Sustainable Resource Development (ESRD) *Water Act*. (Contact ESRD for requirements or see its *Groundwater Evaluation Guideline* document for details.)

15.1 Base Requirements for Water Measurement, Volume Calculation, Production Data Verification, and Audit Trail

For general liquid measurement, inventory determination, liquid volume calculation, production data verification, audit trail, and EFM requirements, see Section 14.

For water meter proving method, see Sections 2.6 and 2.9.

The main difference between measurement of water and other hydrocarbon fluids is that the uncertainty limits are generally less stringent for water. See Sections 1.7 and 1.8.

15.2 Water Measurement and Accounting Requirements for Various Battery/Facility Types

15.2.1 Gas Facilities

The three methods for determining gas production for a gas well are separated gas measurement, effluent measurement, and gas proration. The requirements for determining water production vary among these three methods, and there are also some variations within each method.

15.2.1.1 Single-Well Battery or Gas Group Battery

Each gas well must have permanent separation facilities. Water production must be determined by one of the following methods:

- metering at the water leg of a three-phase separator,
- metering at the water/condensate leg of a two-phase separator and taking a sample of the liquid phase to determine the %S&W and liquid hydrocarbon (see Section 6.4.3),
- directing water production to a tank and delivering by either truck or pipeline for disposition—the monthly production volume is then determined from the delivery volume (measured by the receiving facility) and tank inventory change (by gauging the tank), or

- using a WGR if
  - a three-phase separator is used and the separated water is recombined with the metered gas and metered condensate at the well site in the same pipeline, or
  - a two-phase separator is used and there is no condensate/oil.

15.2.1.2 Gas Proration Batteries Inside Southeastern Alberta Shallow Gas Areas/Zones

Water determination and reporting are not required inside southeastern Alberta shallow gas areas and zones at the well level. They are only required at the battery level. See Section 7.2.

15.2.1.3 Gas Proration Batteries Outside Southeastern Alberta Shallow Gas Areas/Zones

Outside southeastern Alberta shallow gas areas and zones that satisfy the proration requirements in Section 5.4, an individual well WGR may be used to determine water production volume. See Section 7.3.

15.2.1.4 Gas Effluent Proration Battery

Gas wells not configured with separation and measurement of each phase at the wellhead and at which all of the multiphase fluid passes through the same meter are subject to "effluent" or "wet gas" measurement. The water production volume is calculated based on the WGR. See Section 7.4 for ECF-WGR testing and actual well water production calculation requirements and Section 8.4.3 for sampling and analysis requirements.

15.2.1.5 Low-Pressure Gas Systems

If all wells at a gas battery operate at a pressure less than 350 kPa without any mechanical or other external means of water lifting used at any of the wells in the battery, operators may determine water production using one of the following methods:

- group WGR, which is determined by metering the group water production and dividing it by the group gas production on a monthly basis; the resulting WGR is then applied to all wells within the battery based on the wells' reported gas production to determine each well's reported water production; or
- engineering estimates based on the water vapour pressure at the well's flowing conditions; and
- other methods supported by good engineering practice.

15.2.1.6 Water at Gas Gathering System (GGS)

When water is received or disposed of from the GGS, the volume must be measured and reported in accordance with the following requirements:

- If there is no known source(s) of water coming into the GGS, all collected water must be reported on the PRA as water of condensation Activity: REC, Product: WATER, From/To: "ABWC" receipt and "WATER" disposition.

- If there is some known source of water, any delivery volume over and above the known source of water delivered into the GGS must be reported on the PRA as "ABWC" receipt and total disposition. This applies when there are multiple single wells, gas group, and/or other facilities tied into the GGS with commingled water.

- If there is only a single-well battery or one proration battery as the upstream source of the produced water with no water measurement upstream of the disposition location, this location may be designated as the facility group measurement point (battery), and all water collected can be used for reporting from the battery.

- The GGS must report receipt of water from any upstream facilities and report disposition if water is going through the GGS to other facilities further downstream.

15.2.1.7 Gas Plants

Gas plant inlet water measurement is required at each inlet separator when the total receipt volume is >50 m^3 per month for the entire plant. If there is only one inlet separator and no other source of water entering the plant, the plant water disposition plus inventory change may be used for inlet water reporting.

15.2.2 Oil Facilities

The operator must separate the water from the oil and measure the water if the total water production at a well or battery exceeds 50 m^3 per month and the water cut is in excess of 0.5 per cent of the total liquid production. The battery water disposition must be measured if over the 50 m^3 per month limit; the receiving facility is responsible for measurement and reporting of the water disposition.

The two methods for determining oil/water production for oil wells are separated measurement and proration. The requirements for determining water production vary between these two methods, and there are also some variations within each method. (See Section 6.4.)

15.2.2.1 Oil Single-Well Battery (SWB)

For an SWB trucking its emulsion off site, the water production volume is determined by the receiving facility plus the change in inventory when required. (See Section 14.8.1.)

Exception

If an SWB with a two-phase or three-phase separator is delivering produced oil/emulsions by pipeline to another battery and the water production does not exceed 50 m^3 per month, the water cut may be determined by taking three spot samples at intervals at least one week apart within the month and averaging the results. (See Section 14.8.1.)

15.2.2.2 Multiwell Group Oil Battery

Total water production from a multiwell group oil battery must be determined in the same way as from an oil SWB. (See Section 15.2.2.1.)

15.2.2.3 Multiwell Proration Oil Battery

Water production from a multiwell proration oil battery is determined based on well testing and proration from the battery disposition volumes plus inventory change at month end. (See Sections 6.4 and 6.5.)

15.2.3 Water Source Production

Fresh or brackish water from water source wells or other sources, such as rivers and lakes, must be continuously measured before commingling with water or fluids from another source. If a source well is producing gas, the associated gas production must be separated and measured or estimated and reported.

Reporting Requirements (see Figure 15.1)

- Reporting on the PRA must be under the ABWS code for non-ERCB-licensed water sources, such as rivers and lakes. If the production is delivered to a thermal in situ oil sands scheme, it must report disposition to the injection facility (ABIF) and not the bitumen battery of the thermal in situ oil sands scheme.
- For ERCB-licensed water source wells, reporting on the PRA must be under the ABWI code for the well and the ABBT code with subtype 902 code for the battery (single or multiwell) or under the ABIF. If the production is delivered to a thermal in situ oil sands scheme, the well/battery must report disposition to the ABIF and not the bitumen battery of the thermal in situ scheme.
- For ERCB-licensed brine production being used for purposes other than the upstream oil and gas industry, see Section 15.2.9.

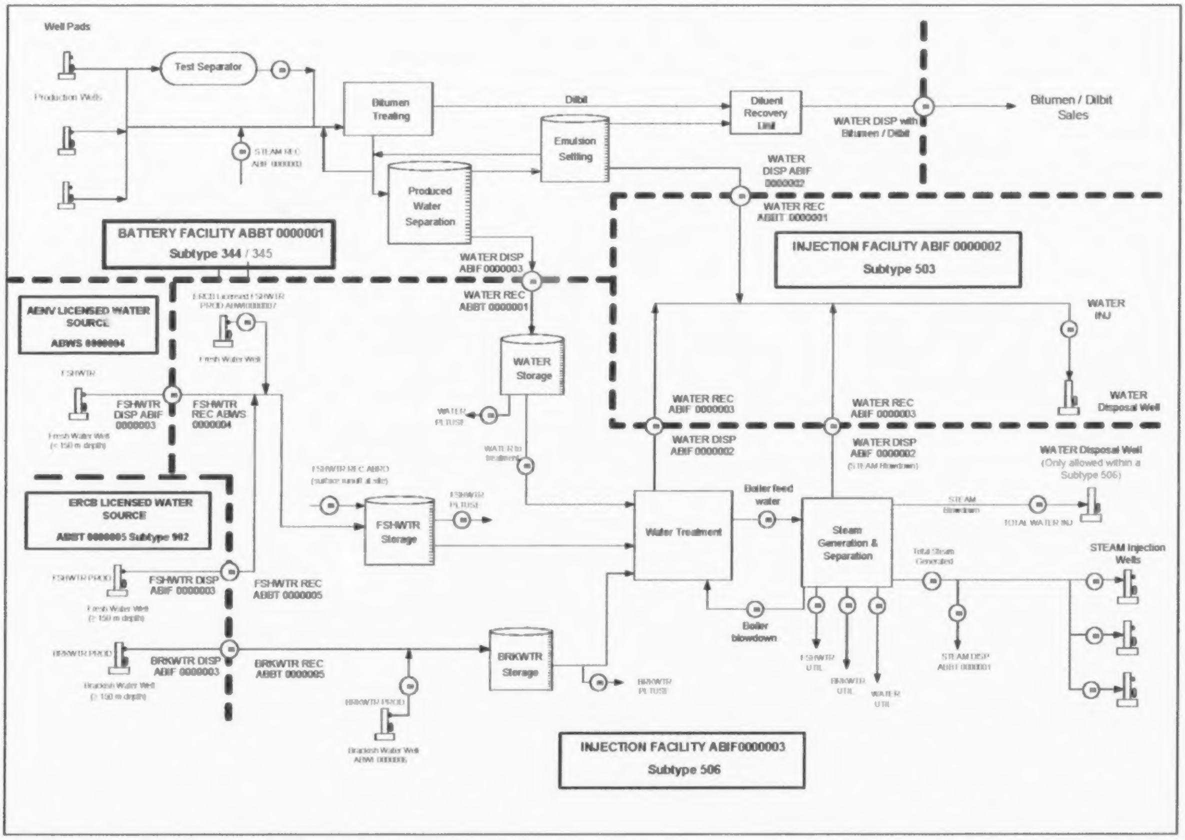

Well Pads
Production Wells
Test Separator
Bitumen Treating
Dilbit
Emulsion Settling
Produced Water Separation
STEAM REC ABIF 0000003
Diluent Recovery Unit
WATER DISP with Bitumen / Dilbit
Bitumen / Dilbit Sales
WATER DISP ABIF 0000002
WATER REC ABBT 0000001
BATTERY FACILITY ABBT 0000001
Subtype 344 / 345
INJECTION FACILITY ABIF 0000002
Subtype 503
WATER DISP ABIF 0000003
WATER REC ABBT 0000001
AENV LICENSED WATER SOURCE
ABWS 0000004
ERCB Licensed FSHWTR PROD ABWI0000007
Fresh Water Well
FSHWTR
FSHWTR DISP ABIF 0000003
FSHWTR REC ABWS 0000004
Fresh Water Well (< 150 m depth)
WATER Storage
WATER PLTUSE
WATER to treatment
WATER INJ
WATER Disposal Well
WATER REC ABIF 0000003
WATER REC ABIF 0000003
WATER DISP ABIF 0000002
WATER DISP ABIF 0000002
(STEAM Blowdown)
WATER Disposal Well (Only allowed within a Subtype 506)
FSHWTR REC ABRO (surface runoff at site)
FSHWTR Storage
FSHWTR PLTUSE
Water Treatment
Boiler feed water
Steam Generation & Separation
STEAM Blowdown
TOTAL WATER INJ
Total Steam Generated
STEAM Injection Wells
ERCB LICENSED WATER SOURCE
ABBT 0000005 Subtype 902
FSHWTR PROD
FSHWTR DISP ABIF 0000003
FSHWTR REC ABBT 0000005
Fresh Water Well (≥ 150 m depth)
Boiler blowdown
BRKWTR PROD
BRKWTR DISP ABIF 0000003
BRKWTR REC ABBT 0000005
Brackish Water Well (≥ 150 m depth)
BRKWTR Storage
BRKWTR PLTUSE
FSHWTR UTIL
BRKWTR UTIL
WATER UTIL
STEAM DISP ABBT 0000001
BRKWTR PROD
Brackish Water Well ABWI 0000006
INJECTION FACILITY ABIF0000003
Subtype 506

Figure 15.1. Example of water source reporting setup

15.2.4 Water Injection and Disposal Facility

Water injected into injection or disposal wells must be continuously measured at each wellhead at the injection site and used for reporting to the PRA. The acid gas injection/disposal measurement scenarios in Section 11.4.4.3 can also be applied to these types of wells. Each injection/disposal well may have its own ABIF reporting code or may be part of another ABIF facility. If there is more than one facility sending water to the ABIF, each receipt must be measured before commingling.

Skim oil recovered from these facilities should not exceed 1.0% of the total received volume based on a six-month rolling average basis. Operators may be contacted to explain the origin of the excessive skim oil.

ERCB Site-Specific Requests

If the 1.0% skim oil limit is exceeded, the ERCB inspector or auditor may direct in writing that the operator implement changes to improve the skim oil percentage, and these directions will become conditions of operation for that facility. Examples of conditions are as follows:

- Investigate where the oil originated from.
- Install proportional sampling or water cut analyzer at the receipt point.
- Inform the source operator to ship emulsion to a proper treatment facility.
- Report the oil receipt at the injection facility from the source facility.

15.2.5 Waste Processing and Disposal Facility

All products received at a waste processing facility must be measured, sampled, analyzed, and reported as oil, water, and solids according to the approval conditions (see *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities* and *Directive 058: Oilfield Waste Management Facility Approvals—Notification and Amendment Procedures*). The disposal facility will auto-populate the PRA with the source of oil and/or water (including solids) if the fluid is produced from an upstream oil and gas facility, such as tank bottom fluids.

15.2.6 Storage and Disposal Cavern

Each storage and disposal cavern must have its own inlet and outlet measurement system, reported as a separate facility on the PRA from the cavern washing stage onwards, and maintain separate oil, water, and solids inventory (see *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities* for more details). The operator must use the following PRA subtype code for cavern reporting:

506 - associated with thermal in situ oil sands schemes

702 - associated with a waste processing facility

503 or 509 - other waste disposal schemes

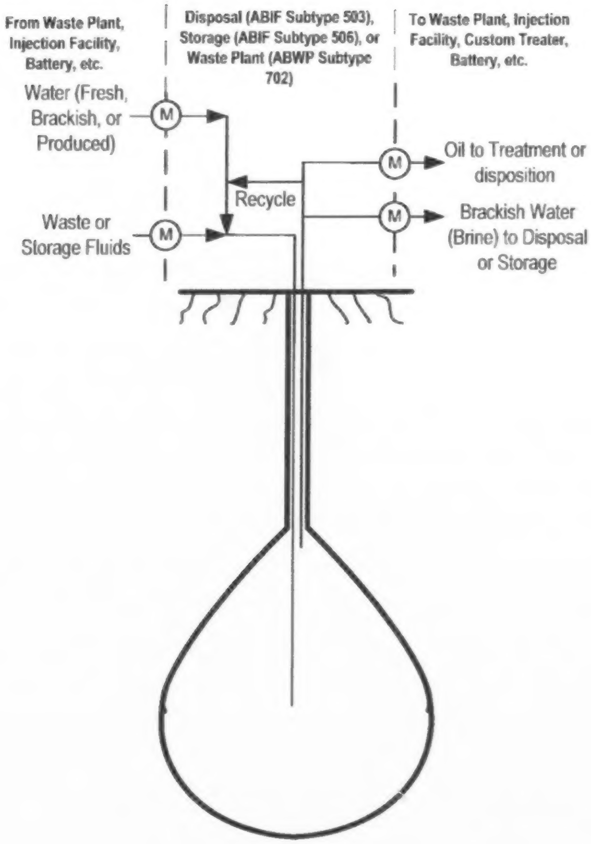

From Waste Plant, Injection Facility, Battery, etc.
Disposal (ABIF Subtype 503), Storage (ABIF Subtype 506), or Waste Plant (ABWP Subtype 702)
To Waste Plant, Injection Facility, Custom Treater, Battery, etc.
Water (Fresh, Brackish, or Produced)
M
Oil to Treatment or disposition
Recycle
Waste or Storage Fluids
Brackish Water (Brine) to Disposal or Storage

Figure 15.2. Cavern measurement

15.2.7 Thermal In Situ Oil Sands Scheme

Thermal in situ oil sands schemes use water to generate steam for injection into formations to produce bitumen. The single point measurement uncertainty requirements for the critical measurement points have been tightened to facilitate water balancing (see Sections 12.4.3 to 12.4.5). The operator must use the PRA subtype code 506 for an injection facility, but a disposal facility could be a subtype 503 or part of the subtype 506 facility. See Figure 15.1.

All steam volume is to be reported as cold water equivalent volume at 15°C.

15.2.8 Downhole Water Disposal or Injection

When water is separated from the gas down hole and injected into another zone or formation without coming to surface, the water volume must be measured if it is greater than 50 m^3/month or estimated if it is 50 m^3/month or less.

15.2.9 Brine Production

When only brine is produced from an ERCB-licensed well and is not used for any upstream oil and gas applications, the well must be reported to the PRA under a subtype 903 battery code. The production must be reported as BRKWTR from the well and also BRKWTR disposition to code ABMC.

15.3 WGR Testing Methodology

Well testing requirements are as follows:

- A WGR test is required for a noneffluent well without continuous water measurement and other well water that is not separated and measured.
- An ECF-WGR test is required for an effluent well (see Section 7.4).
- New wells must have the required tests conducted within the first 30 days of production and annually thereafter, unless otherwise stated or exempted (see Section 5.4). If the operator can demonstrate that the WGR has not stabilized, such as load water has not been fully recovered, multiple tests may have to be conducted over the next few months to determine the stabilized production WGR.
- Wells that could have operation or production characteristics changed because of such events as workovers or chemical stimulations must have a test conducted within 30 days.

15.3.1 WGR Testing

The WGR test must be conducted using a properly sized three-phase separator with measurement of all phases as follows:

- The test must begin only after a stabilization period.
- The test duration must be a minimum of 12 hours.
- If the well is occasionally slugging water, the test duration must be increased to ensure that the test is representative.
- Consistent testing procedures must be used for consecutive tests to identify when a change in a well's flow characteristics has occurred.
- The water volume must be measured by collecting it in a suitable container or by using a water meter.
- The gas and condensate volumes must be measured.
- The condensate must be sampled during every test and analyzed for the components to determine an updated gas equivalent factor. The sample may be taken from the condensate leg of a three-phase separator or the liquid leg of a two-phase separator. The water must be removed from the condensate before the analysis.
- The test volumes and date for each test must be recorded.
- The WGR must be determined by dividing the water volume by the sum of the measured gas volume and the gas equivalent volume (GEV) of the measured condensate (see Section 7.3.2).
- If a three-phase separator is not available, alternative equipment, such as a two-phase separator with a total liquid meter and continuous water cut analyzer, is acceptable. Other options that provide equivalent liquid volume accuracy may also be considered on a case-by-case basis by the ERCB.

15.3.2 WGR Calculation

WGR calculation for a gas group battery is as follows (for other proration batteries, see Section 7):

1) Calculate the total monthly gas production volume

Total monthly well gas volume = Well measured gas volume + GEV of well measured condensate (if recombined)

2) Calculate the WGR for each well

The WGR is to be calculated to six decimal places and then rounded to five decimal places, as follows:

WGR = Well test water volume / (Well test gas volume + GEV of well test condensate [if recombined])

3) Calculate actual water production for each well

Using the WGR, actual water production for the well is calculated as follows:

Actual monthly well water volume = Total monthly well gas volume x WGR

Appendix 1 Sections Under Development

None currently under development.

Appendix 2 ERCB Documents Replaced Fully or Partially by *Directive 017: Measurement Requirements for Oil and Gas Operations*

Total Replacement (rescinded on date *Directive 017* becomes effective):

Directive 004: Determination of Water Production at Gas Wells
Directive 049: Gas Density Measurement Frequency
Interim Directive (ID) 90-2: Gas Meter Calibration
ID 91-3: Clarification (May 2001): Heavy Oil/Oil Sands Operations
ID 94-1: Measurement of Oil, Gas & Water Production
Informational Letter (IL) 86-03: Automated Measurement Systems
IL 87-1: Compressibility Factors Used in Gas Volume Calculations and Physical Property Data for Natural Gases
IL 89-16: Guidelines for Automated Measurement System Applications, ERCB Guide G-34 Comparative Chart Data
IL 90-6: Measurement Guidelines—Trucked Oil Production
IL 91-9: Exemption from Gas Measurement Crude Oil/Bitumen Wells
IL 92-8: Crude Oil Pipeline Truck Terminal Measurement Guidelines
IL 92-9: Revised Reporting Procedures—Load Fluids
IL 93-1 Gas Density Measurement Frequency—Orifice Meter
IL 93-10 Revised Measurement and Accounting Procedures for Southeastern Alberta Shallow Gas Wells
IL 94-7: Coriolis Force Flowmeters

Partial Replacement:

For sections in ILs, IDs, and directives that are no longer effective, see the documents on the ERCB website www.ercb.ca:
Directive 046: Production Audit Handbook
Directive 060: Upstream Petroleum Industry Flaring Guide
Guide 34: Guidelines for Automated Measurement System Applications—Note that for those systems approved under *Guide 34*, the guide is still in effect.
ID 91-3: Heavy Oil/Oil Sands Operations

Appendix 3 Glossary

The definitions that follow are for the purposes of this directive only.

Absolute Density of Gas - The gas's mass per unit volume at a specific pressure and temperature. Absolute densities are generally expressed in kg/m³ at 101.325 kPa(a) and 15°C.

Absolute Density of Liquid - The liquid's mass per unit volume at a specific pressure and temperature. Absolute density of a liquid is generally expressed as kg/m³ at 101.325 kPa(a) and 15°C.

Accuracy - The ability of a measuring instrument to indicate values closely approximating the true value of the quantity measured.

Acid Gas - Gas separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H_2S), totally reduced sulphur compounds, and/or carbon dioxide (CO_2).

Allowable - Used in connection with a well, means the amount of oil or gas a well is permitted to produce, in accordance with an order of the ERCB Board for this purpose, after application of any applicable penalty factor.

Bias - Any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the result of a predictable systematic error.

Battery - A system or arrangement of tanks or other surface equipment receiving the effluents of one or more wells prior to delivery to market or other disposition, and may include equipment or devices for separating of the effluents into oil, gas, or water and for measurement.

Block - An area or part of a pool consisting of drilling spacing units grouped for the purpose of administering a common, aggregate production allowable.

Butane - In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus.

Calibration - Procedures or operations that establish the accuracy of the values indicated by a measuring device as compared to the values indicated by a calibration instrument that has accuracy traceable to a suitable measuring standard. Adjustments are made, if required, to the measuring device to make it comparable to the calibration instrument. May also refer to the procedure used to determine the volume of a prover.

Central Processing Facility - A battery system or arrangement of tanks or other surface equipment receiving the effluent of one or more wells or a satellite prior to delivery to market or other disposition; may include equipment or devices for separating the effluents into crude bitumen, gas, or water for the injection and distribution of air, steam, gas, hydrocarbon, or other materials, for water treatment and recycling, and for measurement but does not include a processing plant.

Clean Oil - Oil with 0.5% S&W or less.

Common Crown or Freehold Royalty - When all the wells in a battery are produced under Crown mineral leases and the Crown receives the same royalty rate for each well, or when under leases granted by one Freehold mineral holder, the Freehold mineral holder receives the same royalty rate for each well. If there is more than one Freehold mineral holder for the wells in a battery, the total royalty rate for each well is the same.

Common Ownership - All wells in a battery belong to the same working interest participant, or if there is more than one working interest participant, each working interest participant has the same percentage interest in each well in the battery.

Compressor Station - An installation of service equipment that receives natural gas from a well, battery, or gathering system prior to delivery to market or other disposition and is intended to maintain or increase the flowing pressure of the gas; includes any equipment for measurement.

Condensate - A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated.

Confidence Level - The degree of confidence that may be placed on an estimated range of uncertainty.

Crude Bitumen - A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well.

Crude Oil - A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir, and that is liquid at the conditions under which its volume is measured or estimated; includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen.

Custom Treating Plant - A system or arrangement of tanks and other surface equipment receiving oil/water emulsion exclusively by truck for separation prior to delivery to market or other disposition.

Dehydrator - An apparatus or a process designed and used to remove water from raw gas.

Delivery Point - The point at which the delivery of oil or gas production from a battery or facility is measured. The volumes determined at this point are typically used in royalty calculations (royalty trigger points), such as sales, cross border, gas plant to facility, or gas plant to gas plant meters.

Delivery Point Measurement - The type of measurement required at a delivery point.

Electronic Flow Measurement (EFM) - Any flow measurement and related system that collects data and performs flow calculations electronically.

Emulsion - A combination of two immiscible liquids, or liquids that do not mix together under normal conditions.

Enhanced Recovery - The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool; such artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of

- aiding in the lifting of fluids in the well; or
- stimulating the reservoir at or near the well by mechanical, chemical, thermal, or explosive means.

Equilibrium Vapour Pressure (EVP) - The pressure at which a liquid and its vapour are in equilibrium at a given temperature. When a hydrocarbon liquid has an EVP above the standard pressure (101.325 kPa at 15°C), the EVP at 15°C is the pressure base.

Error - The difference between true and observed values.

Error (random) - An error that varies in an unpredictable manner when a large number of measurements of the same variable are made under effectively identical conditions.

Error (spurious) - A gross error in procedure (for example, human errors or machine malfunctions).

Error (systematic) - An error that in the course of a number of measurements made under the same conditions on material having the same true value of a variable either remains constant in absolute value and sign or varies in a predictable manner. Systematic errors result in a bias.

Ethane - In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane.

Exception - Circumstances under which if specific criteria are met or approval is granted, measurement devices or procedures are allowed to deviate within specified limits from base measurement requirements.

Facility - Any building, structure, installation, equipment, or appurtenance over which the ERCB has jurisdiction and that is connected to or associated with the recovery, development, production, handling, processing, treatment, or disposal of hydrocarbon-based resources or any associated substances or wastes; includes, without limitation, a battery, processing plant, gas plant, oilfield waste management facility, central processing facility as defined in the *Oil Sands Conservation Regulation* (AR 76/88), compressor, dehydrator, separator, treater, custom treating plant, produced water-injection plant, produced water disposal plant, miscible flood injection plant, satellite, or any combination of any of these, but does not include a well, pipeline as defined in the *Pipeline Act*, mine site or processing plant as defined in the *Oil Sands Conservation Regulation* (AR 76/88), or mine site or coal processing plant as defined in the *Coal Conservation Act*.

Gas - Raw gas or marketable gas or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated.

Gas Battery - A system or arrangement of surface equipment receiving the effluent from one or more gas wells that provides separation, measurement, dehydration, dew point control, compression, or other gas handling functions prior to the delivery to market or other disposition; does not include gas processing equipment.

Gas Equivalent Factor (GEF) - A factor based on the composition of a hydrocarbon liquid mixture that is used to convert the same hydrocarbon liquid mixture to its equivalent gas volume. This factor is mixture dependent and not a constant for all mixtures.

Gas Equivalent Volume (GEV) - The volume of gas (10^3 m^3) that would result from converting 1 m^3 of liquid into a gas by applying a GEF to the liquid volume.

Gas Fractionation Plant - An arrangement of equipment to reprocess an NGL inlet into one or more in-stream components.

Gas Gathering System - A reporting entity that may consist of pipelines used to move gas production from oil batteries, gas batteries, and/or other facilities to another facility (usually a gas plant); may include compressors, line heaters, dehydrators, measurement, and other equipment.

Gas-in-Solution (GIS) - Gas dissolved in an oil volume under pressure.

Gas Plant - A system or arrangement of equipment used for the extraction of hydrogen sulphide, helium, ethane, natural gas liquids, or other substances from raw gas. Does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigeration, desiccant). In addition, does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of non-regenerative scavenging chemicals that generate no hydrogen sulphide or sulphur dioxide.

Gas Well - A well that produces primarily gas from a pool or portion of a pool wherein the hydrocarbon system is gaseous or exhibits a dew point on reduction of pressure, or any well so designated by the ERCB.

Good Production Practice (GPP) - Production of crude oil or raw gas at a rate

- not governed by a base allowable, but
- limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain his share of production.

Heavy Oil - Crude oil having a density of 920 kg/m^3 or greater at 15°C.

High Vapour Pressure Liquids - Fluids extracted from raw gas that has been processed at a gas facility, such as ethane, propane, butane, NGL, and in some cases pentanes plus.

Hydrocarbon Liquid - A fluid in the liquid state that may consist of one or more of the following: oil, bitumen, condensate, ethane, propane, butane, pentane plus, or other heavier hydrocarbon compounds.

Initial Qualifying Criteria - Criteria that must be met to qualify for an exception. If the initial qualifying criteria have been met and the exception is implemented, it may remain in place indefinitely, as long as the wells do not meet any of the revocation clauses and there are no physical additions to the battery or facility (e.g., new wells or zones). If additions or changes are made to the battery or facility, the initial qualifying criteria must be met for all the wells or zones added to the battery or facility for the exception to remain in place.

Injection/Disposal Facility - A system or arrangement of surface equipment associated with the injection or disposal of any substance through one or more wells.

Innage Gauge - The depth of liquid in a tank as measured from the surface of the liquid to the tank bottom or to a fixed datum plate.

In Situ Operation

- a scheme or operation ordinarily involving the use of well production operations for the recovery of crude bitumen from oil sands, or
- a scheme or operation designated by the ERCB as an in situ operation, but does not include a mining operation.

Lease Automatic Custody Transfer (LACT) - defined by API MPMS, Chapter 1.

Licensee - The holder of a licence according to the records of the ERCB; includes a trustee or receiver-manager of property of a licensee.

Liquefied Petroleum Gas (LPG) - LPG consists primarily of propane (C3) and butane (C4) in a mixture or essentially pure form, with minor components ranging from ethane (C2) to normal hexane (C6). It is produced either as a by-product of natural gas processing or during refining and processing operations.

Liquid/Gas Ratio (LGR) - A ratio calculated by dividing the total water and/or condensate test volumes by the measured test gas volume.

Load Fluids - Any hydrocarbon- and/or water-based fluids used at any stage in the life of a well (completion, servicing, regular operation, or abandonment). It includes fluids injected into a flow line between a well and the battery to which it produces (e.g., hot oil, dewaxing chemicals).

Load Oil - Hydrocarbon-type fluids used as load fluid, including crude oil, condensate, refined oils, and oil-based or oil-soluble chemicals.

Load Water - Water-type fluids used as load fluid, including produced/fresh/brackish water and water-based or water-soluble chemicals.

Master Meter - A meter of known accuracy that is connected in series with another meter for the purpose of checking the accuracy of that meter and providing a meter factor.

Maximum Uncertainty of Monthly Volume - Relates to the limits applicable to equipment and/or procedures used to determine the total monthly volume.

Mean - A value in the middle of two extremes (the two values farthest apart in a group of values).

Measured Gas Source(s) - Single-phase measured gas source(s) downstream of separation and removal of liquids; also includes the gas equivalent volume (GEV) of measured condensate if the condensate is recombined after measurement with the gas downstream of the separator.

Measured Oil - Oil measured using equipment and/or procedures meeting delivery point measurement requirements and/or uncertainty limits. For emulsion, the delivery point measurement uncertainty limits apply to the total volume determination only.

Measurement - A procedure for determining a value for a physical variable.

Measurement by Difference - Any situation where an unmeasured volume is determined by taking the difference between two or more measured volumes.

Measuring Standard - A device used in calibration or proving that has a known value traceable to national reference standards maintained by the National Research Council in Ottawa, Ontario.

Meter Factor - A dimensionless number used to correct indicated meter volumes to adjusted volumes if the two volumes differ due to operational conditions (e.g., gas entrained in liquids, meter slippage, meter wear). It is not to be confused with the "K Factor," which is used to convert the number of pulses generated by a meter (where electronic pulse technology is the basis of the meter operation) into units of volume. The K Factor is typically determined by the meter manufacturer and does not take into consideration all of the specific operational conditions the meter may be subjected to.

Metering Difference - The volume used to balance, on a monthly basis, any difference that occurs between the measured inlet/receipt volumes and the measured outlet/disposition volumes at a facility.

Methane - In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide.

Natural Gas Liquid (NGL) - Propane, butanes, or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate.

Oil - Condensate or crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing, that is liquid at the conditions under which its volume is measured or estimated.

Oil Battery - A system or arrangement of surface equipment receiving the effluent from one or more oil wells that provides separation, treating, measurement, and other oil handling functions prior to the delivery to market or other disposition.

Oilfield Waste - An unwanted substance or mixture of substances that results from the construction, operation, abandonment, or reclamation of a facility, well site, or pipeline, but does not include an unwanted substance or mixture of substances from such a source that is received for storage, treatment, disposal, or recycling at a facility that is regulated by the Department of Environment.

Oilfield Waste Management Facility (OWMF) - Integrated waste treatment facility as defined in *Directive 047*.

Oil Well - A well that produces primarily liquid hydrocarbons from a pool or portion of a pool wherein the hydrocarbon system is liquid or exhibits a bubble point on reduction of pressure, or any well so designated by the ERCB.

Operator - With respect to a well or facility, a person who

- has control of or undertakes the day-to-day operations and activities at a well or facility, or
- keeps records and submits production reports for a well or facility to the ERCB, whether or not that person is also the licensee or approval holder of the well or facility.

Outage Gauge - The distance from a reference point at the top of a tank to the surface of the liquid. This "gauge" is then subtracted from the full height gauge (from the same reference point) of the tank to determine the depth of the liquid.

Pentanes Plus - A mixture mainly of pentanes and heavier hydrocarbons, which ordinarily may contain some butanes, that is obtained from the processing of raw gas, condensate, or crude oil.

Pipeline - Any pipe or any system or arrangement of pipes wholly within Alberta and whereby oil, gas, or synthetic crude oil or water incidental to the drilling for or production of oil, gas or synthetic crude oil is conveyed, and

- includes all property of any kind used for the purpose of, in connection with, or incidental to the operation of a pipeline in the gathering, transporting, handling, and delivery of oil, gas, synthetic crude oil, or water, but
- does not include any pipe or any system or arrangement of pipes that constitutes a distribution system for the distribution within a community of gas to ultimate consumers.

Pool - A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation.

PRA - Petroleum Registry of Alberta.

Propane - In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes.

Proration - An accounting procedure or system in which the total actual monthly battery production is equitably distributed among the wells in the battery.

Proration Battery - A battery for which all well production is commingled prior to the total battery production volumes being separated and measured (or estimated where appropriate) as single phases. Individual monthly well production volumes are estimated based on periodic well tests and are corrected to the actual monthly volumes through the use of proration factors.

Prover - A device used to collect and determine the volume of a sample of fluid that has passed through a meter. Provers typically use volumetric or gravimetric means to determine the quantity of the sample.

Prover Run - The operation of a prover or master meter whereby a representative volume is sampled and measured, and that sample volume is compared to the volume indicated by a meter through which the same sample has passed to determine a meter factor.

Proving - The procedures or operations whereby a prover volume is compared to an indicated meter volume (both corrected to applicable pressure and temperature conditions). The prover volume divided by the indicated meter volume yields a meter factor. The meter factor is subsequently applied to indicated meter volumes to determine the adjusted or corrected volume. If the meter is connected to an electronic readout, the meter factor may be incorporated into the software such that the indicated meter volume is already corrected to read the adjusted volume. (Care should be taken in such cases not to apply the meter factor again – in such cases the meter factor should be indicated on the tag or label as being 1.0000.)

Raw Gas - A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these, that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated.

Relative Density of Gas - The ratio of the mass of the gas to the mass of an equal volume of air. It is also referred to as gas gravity or specific gravity of gas.

S&W - "Sediments and water," commonly refers to settled solid and/or semi-solid components and water in tanks and other containment vessels.

Sales Gas - A mixture mainly of methane originating from raw gas, if necessary through the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material.

Satellite or Satellite Battery - Surface equipment located between a number of wells and the main battery that is intended to separate and measure the production from each well, after which the fluids are recombined and piped to the main battery for separation/treating, measurement, and storage or delivery.

Segregate - To confine each fluid in a well to its proper pool or flow channel so that it is separate from the fluid in or passing from or to any other pool.

Separator - An unfired apparatus specifically designed and used for separating fluids produced from a well into two or more streams; does not include a dehydrator.

Single Point Measurement Uncertainty - Relates to the limits applicable to equipment and/or procedures used to determine a specific volume at a single measurement point.

Solid - A substance that does not contain free liquids and is not gaseous at standard conditions.

Solution Gas - Volatile hydrocarbons that are dissolved in solution with produced oil or bitumen.

Stock Tank Vapours - The solution gas present in the oil/bitumen storage tanks that may be released from the tanks.

Synthetic Crude Oil - A mixture mainly of pentanes and heavier hydrocarbons, which may also contain sulphur compounds, that is derived from crude bitumen and is liquid at the conditions under which its volume is measured or estimated; includes all other hydrocarbon mixtures so derived.

Tank - A device designed to contain materials produced, generated, and used by the upstream petroleum industry that is constructed of impervious materials to provide structural support; may include such materials as concrete, plastic, fiberglass reinforced plastic, or steel.

Thief - An industry term for a bottom-closure, core-type liquid sampling device used to secure samples from storage tanks.

Treater - A fired apparatus specifically designed and used for separating gas and water from crude oil.

Truck Terminal - A system or arrangement of tanks and other surface equipment that receives hydrocarbon liquids by truck for the purpose of delivering those liquids into a pipeline.

Well - An orifice in the ground completed or being drilled

- for the production of oil or gas,
- for injection to an underground formation,
- as an evaluation well or test hole, or
- to or at a depth of more than 150 m for any purpose;

does not include such an orifice for the purpose of discovering or evaluating a solid inorganic mineral that does not or will not penetrate a stratum capable of containing a pool or oil sands deposit.

Well Event - A unique identifier code for an interval, zone, pool, or horizon in a well. A well may be completed in multiple intervals, zones, pools, or horizons, each of which is identified as a well event.

Appendix 4 Water-Cut (S&W) Procedures

Water-cut procedures are divided into three categories and described on the following pages. Different procedures are specified for the three categories to improve accuracy and consistency of the S&W determinations. The use of "mason jars" with measuring tape attached is not acceptable for determining S&W. S&W percentage must be recorded to a minimum of one decimal place.

More detail on S&W determination is in API MPMS, Chapter 10.4: Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure). The ERCB will consider any procedure that meets API MPMS, 10.4 standards to be in compliance with this directive. It is the responsibility of the licensee/operator to show that its procedure meets the above API standard.

Category 1—for 0 to 10% S&W

Obtain a representative sample of liquid.

Shake the sample container vigorously to mix it before pouring into the centrifuge tubes.

1) Fill each of two tubes with exactly 100 parts (50 ml) of the sample.

2) Fill each tube with the solvent solution (premixed solvent and demulsifier) to the 200-part mark (100 ml).

3) Stopper each tube tightly and invert 10 times.

4) Loosen the stoppers and immerse the tubes in a preheater. Heat the contents to 60°C ±3°C.

5) Stopper each tube tightly and invert 10 times.

6) Place the tubes in the centrifuge machine in a balanced condition and spin for 5 minutes.

7) Immediately after the centrifuge comes to rest, use a thermometer to verify that the sample temperature is within 9°C of the test temperature.

   If sample temperature is within 9°C, go to step 8. If sample temperature is not within 9°C, go back to step 4, raise the temperature, and repeat steps 5, 6, and 7.

8) Read and record the volume of water and sediment at the bottom of each tube.

9) Reheat the tubes to the initial spin temperature and return them, without agitation, to the centrifuge machine. Spin for an additional 5 minutes. Repeat the procedure until two consecutive, consistent readings are obtained.

   For the test to be considered valid, a clear interface must be observed between the oil layer and the separated water. No emulsion should be present immediately above the oil/water interface. A test comprises TWO TUBES of the SAME SAMPLE. Compare the readings of the two tubes. If the difference is greater than one subdivision on the centrifuge tube, the test is invalid and should be repeated.

10) Calculation and reporting:

For 200 ml tubes: the percentage of water and sediment is the average, to three decimal places, of the values read directly from the two tubes.

For 100 ml tubes: read and record the volume of water and sediment in each tube. Add the readings together and report the sum as the percentage of water and sediment.

Example 1 (see Figure A4.1)

100 ml centrifuge tubes	200 ml centrifuge tubes
If reading from each tube is the same:	
Reading from each tube = 0.50 ml	Reading from each tube = 1.00 ml
Water cut = (0.50 + 0.50) ÷ 100 = 1.0 %	Water cut = 1.00 ÷ 100 = 1.0 %
If reading from each tube is not the same:	
Reading from 1st run of each tube = 0.50, 0.60 ml	Reading from 1st run of each tube = 1.00, 1.05 ml
Reading from 2nd run of each tube = 0.50, 0.55 ml	Reading from 2nd run of each tube = 1.00, 1.10 ml
Water cut = (0.50 + 0.60 + 0.50 + 0.55) ÷ 2 ÷ 100 = 1.1%	Water cut = (1.00 + 1.05 + 1.00 + 1.10) ÷ 4 ÷ 100 = 1.0%

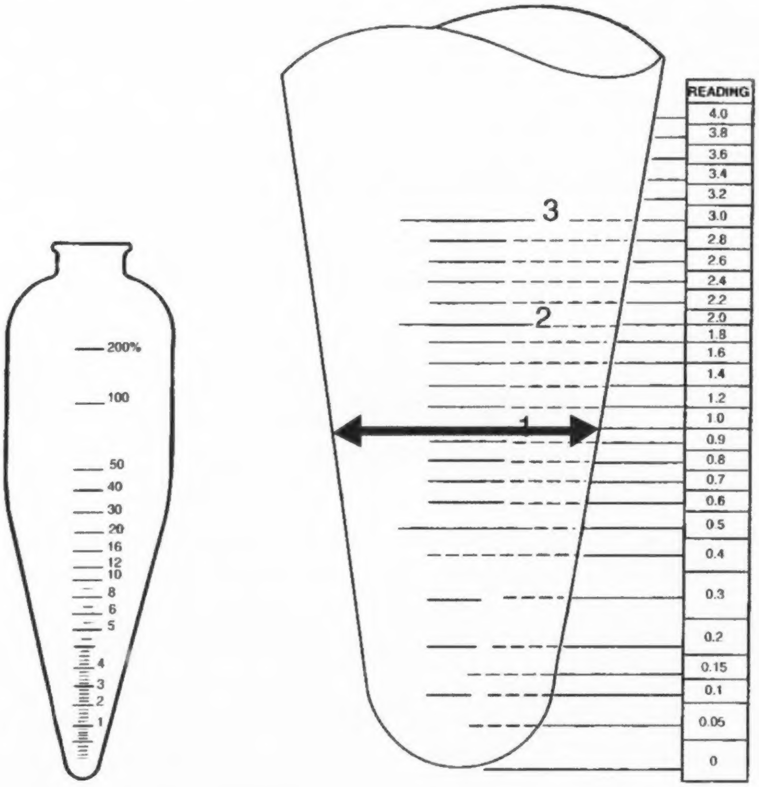

200%
100
50
40
30
20
16
12
10
8
6
5
4
3
2
1
3
2
1
READING
4.0
3.8
3.6
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.15
0.1
0.05
0

Figure A4.1. Reading a centrifuge tube

Category 2—for 10 to 80% S&W

Obtain the maximum representative sample of liquid feasible (minimum 800 ml).

Transfer the entire sample into an adequately sized graduated cylinder. It may be necessary to wash out the inside of the sample container with a measured volume of solvent to ensure that all of the oil is removed. If this is done, it is necessary to account for the additional amount of solvent added when calculating the water-cut percentage.

Place the graduated cylinder into a heat bath at or above treater temperature (or at or above 60°C if no treater is involved) until the sample temperature and free water fallout have stabilized. A clear oil/water interface must be visible.

Read and record the total volume, the volume of free water, and the volume of oil/emulsion in the graduated cylinder. Calculate the free water percentage as follows:

Percentage of free water = (Volume of free water ÷ Total volume) x 100%

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Percentage of free water =

Volume of free water ÷ (Total volume – Volume of solvent/demulsifier) x 100%

Draw 100 ml from the oil/emulsion portion in the graduated cylinder and fill each of two 100 ml centrifuge tubes to exactly the 50 ml mark. Add solvent to bring the level in the tubes to exactly the 100 ml mark. The procedures previously outlined for samples with 0 to 10% water cut are to be followed, with the exception that the water-cut readings from both tubes are to be added together, even if they are not the same.

Note that if 200 ml tubes are to be used, a larger initial sample will be required, and if the water-cut readings from both tubes are not the same, the average of both tubes is to be used as the resultant water cut of the oil/emulsion portion.

From the spinning results, calculate the percentage of water remaining in the oil/emulsion portion as follows:

Percentage of water remaining =

Total oil/emulsion volume in cylinder x Water-cut % of oil/emulsion ÷ Total volume

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Percentage of water remaining =

(Total oil/emulsion volume in cylinder x Water-cut % of oil/emulsion) ÷ (Total volume – Volume of solvent/demulsifier)

Calculate the total water-cut percentage as follows:

Total water-cut % = % free water + % water remaining

Example 2 (see Figure A4.2)

1000 ml graduated cylinder
% of free water = 600 ml ÷ 900 ml x 100% = **66.7%**
% of water remaining = 300 ml x 10%* ÷ 900 ml = **3.3%**
Total water-cut % = 66.7% + 3.3%= **70.0%**

* Water cut of oil portion determined by spinning samples

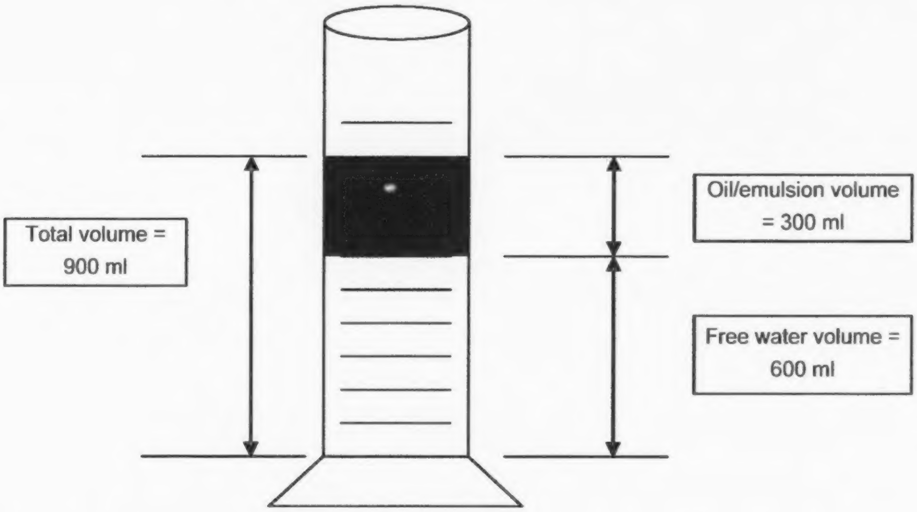


Figure A4.2. Water-cut % from 10 to 80%

Category 3—for 80 to 100% S&W

Obtain the maximum representative sample of liquid feasible (minimum 800 ml).

Transfer the entire sample into an adequately sized graduated cylinder. It may be necessary to wash out the inside of the sample container with a measured volume of solvent to ensure that all of the oil is removed. If this is done, it is necessary to account for the additional amount of solvent added when calculating the water-cut percentage.

Place the graduated cylinder into a heat bath at or above treater temperature (or at or above 60°C if no treater is involved) until the sample temperature and free water fallout have stabilized. A clear oil/water interface must be visible. A narrow-necked graduated cylinder should be used to improve accuracy in sample measurement when the water cut is above 90% (see Figure A4.4).

Read and record the total volume and the volume of free water in the graduated cylinder. If no solvent or demulsifier has been added to the sample, calculate the water-cut percentage as follows:

Water-cut % = Volume of free water ÷ Total volume x 100%

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Water-cut % = Volume of free water ÷ (Total volume - Volume of solvent/demulsifier) x 100%

The water content of the oil/emulsion portion in the graduated cylinder does not have to be determined, due to the limited amount of the oil/emulsion portion of the sample available at these high water contents. However, if there is enough oil/emulsion volume, the licensee may choose to use the same procedure as that described for the 10 to 80% S&W, with the option to centrifuge only one sample.

Example 3 (see Figure A4.3)

1000 ml graduated cylinder
Water-cut % = 900 ml ÷ 1000 ml x 100% = 90.0%

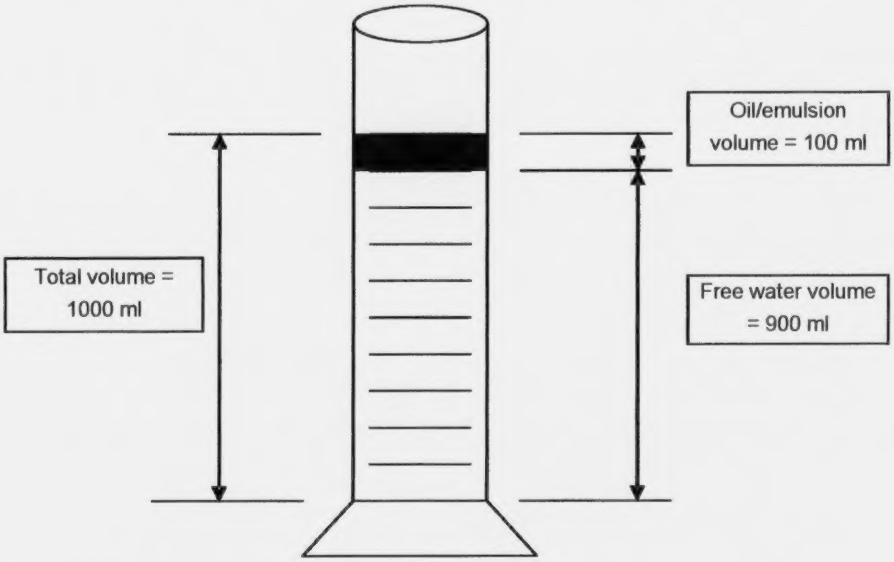


Figure A4.3. Water-cut % over 80%

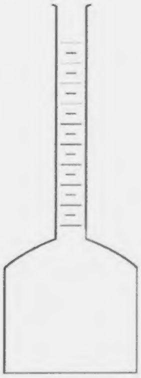


Figure A4.4. Narrow-necked graduated cylinder

Appendix 5 On-site Analytical Techniques for H_2S Measurement

On-site measurement of H_2S in natural gas streams can be accomplished by several different methods. The appropriate method should be selected with an understanding of the benefits and limitations of each method.

Length of Stain Tubes (GPA Standard 2377-05): For concentrations below 1500 ppm, the most convenient and economical choice is the use of a "length of stain tube." These devices can suffer from some interference, affecting both the precision and the accuracy of the measurements. Nonetheless, for many purposes this technique can provide H_2S measurements of a suitable quality. The understanding is that the measurement uncertainty is potentially less than the risk of H_2S degradation if a laboratory method were employed. If the most accurate measurements are required, a second sample can be collected in a suitably inert container and returned to a laboratory for prompt analysis.

Tutweiler Titration (GPA Standard C-1): This technique is the method of choice for on-site analysis when the concentration of H_2S is greater than 1500 ppm. The Tutweiler titration can provide accurate measurements of H_2S using suitably calibrated glassware and chemicals. Operator skill and proper recording of temperatures and barometric pressure are also key elements for this technique.

Instrumental (in-lab) Analytical Techniques for H_2S Measurement

Gas Chromatography with Sulphur Selective Detection (ASTM D-5504-01): Sulphur selective detectors can be coupled with gas chromatographs to achieve a low detection limit for H_2S and other sulphur compounds, such as mercaptans, sulphides, and disulphides. These instruments are ideal for low concentrations ranging from sub ppm up to several thousand ppm. The sulphur selective detectors are much less susceptible to hydrocarbon interferences and can also identify other sulphur-containing compounds in addition to H_2S. Suitable sulphur selective detectors are sulphur chemiluminescence detectors (SCD) and pulsed flame photometric detectors (PFPD).

Gas Chromatography with Thermal Conductivity Detection: Thermal conductivity detectors can be coupled with gas chromatographs to analyze for intermediate to high levels of H_2S. H_2S can be adequately resolved from hydrocarbon components to allow for specific detection. The columns selected for this type of analysis must offer a good balance between high resolution (specificity of H_2S) and low adsorption of H_2S. Detection limits for H_2S levels as low as 300 ppm can be achieved under the right conditions, and the method can also be calibrated for values approaching 100 per cent H_2S. The analytical range for these systems should not exceed the linear range of the column and detector combination. Therefore, acceptable calibration ranges must yield a linear calibration curve (minimum 4 points) with an R-squared value of no less than 0.99.

Appendix 6 Gas Equivalent Volume Determination

Liquid Analysis Example

Component	Volume Fractions	Mole Fractions	Mass Fractions
N2	0.0006	0.0019	0.0008
CO2	0.0081	0.0158	0.0109
H2S	0	0	0
C1	0.0828	0.1617	0.0405
C2	0.1117	0.1462	0.0687
C3	0.1275	0.1533	0.1056
IC4	0.0394	0.0398	0.0362
NC4	0.0891	0.0935	0.0849
IC5	0.0483	0.0436	0.0492
NC5	0.0540	0.0493	0.0556
C6	0.0765	0.0614	0.0835
C7	0.0880	0.0678	0.1054
C8	0.0827	0.0589	0.1032
C9	0.0570	0.0368	0.0726
C10	0.0363	0.0222	0.0480
C11	0.0225	0.0131	0.0305
C12+	0.0755	0.0347	0.1044
TOTAL	1.0000	1.0000	1.0000

Properties of C5+ & C7+ portion of sample					
	Mol. Fractions	Wt. Fractions	Liq. Vol. Fractions	Mol. Wt. (kg/kmol)	Absolute Density (AD) (kg/m^3)
C5+	0.3878	0.6524	0.5408	107.7	739.33
C7+	0.2335	0.4641	0.3620	127.2	785.29

A6.1 Gas Equivalent Factor by Volume Fraction Calculation

GEF = Total (Pseudo 10^3 m^3 Gas / m^3 Liquid)

Condensate Stream : ______________________________

Component	**Vol. Fraction Liquid Analysis**		**10^3 m^3 Gas / m^3 Liquid @ 101.325 kPa & 15°C**		**Pseudo 10^3 m^3 Gas / m^3 Liquid**
N2		x	0.68040	=	
CO2		x	0.44120	=	
H2S		x	0.55460	=	
C1		x	0.44217	=	
C2		x	0.28151	=	
C3		x	0.27222	=	
IC4		x	0.22906	=	
NC4		x	0.23763	=	
IC5		x	0.20468	=	
NC5		x	0.20681	=	
C6		x	0.18216	=	
C7		x	0.16234	=	
C8		x	0.14629	=	
C9		x	0.13303	=	
C10		x	0.12194	=	
				Total =	

Note: For C5+, C6+, or C7+ Sample:

Properties of C5+, C6+, or C7+ sample @ 15°C

AD = ☐

Mol. Wt. = ☐

10^3 m^3 Gas / m^3 Liquid = 23.645 (m^3/kmol) x AD (kg/m^3) / Mol. Wt. (kg/kmol)

= ☐ Input this factor to the table above for C5+, C6+, or C7+

GEF = Total (10^3 m^3 Gas / m^3 Liquid)

= ☐ **(10^3 m^3 Gas / m^3 Liquid)**

Example 1

Gas Equivalent Factor by Volume Fraction Calculation

GEF = Total (Pseudo 10^3 m^3 Gas / m^3 Liquid)

Condensate Stream : ______________________________

Component	Volume Fraction Liquid Analysis		10^3 m^3 Gas / m^3 Liquid @ 101.325 kPa & 15°C		Pseudo 10^3 m^3 Gas / m^3 Liquid
N2	0.0006	x	0.68040	=	0.0004
CO2	0.0081	x	0.44120	=	0.0036
H2S	0	x	0.55460	=	
C1	0.0828	x	0.44217	=	0.0366
C2	0.1117	x	0.28151	=	0.0314
C3	0.1275	x	0.27222	=	0.0347
IC4	0.0394	x	0.22906	=	0.0090
NC4	0.0891	x	0.23763	=	0.0212
IC5	0.0483	x	0.20468	=	0.0099
NC5	0.0540	x	0.20681	=	0.0112
C6	0.0765	x	0.18216	=	0.0139
C7+	0.3620	x	0.14598	=	0.0528
		x		=	
	1.0000			Total =	0.2247

Note: For C7+ Sample:

Properties of C7+ sample @ 15 °C

AD = 785.29

Mol. Wt. = 127.2

10^3 m^3 Gas / m^3 Liquid = 23.645 (m^3/kmol) x AD (kg/m^3) / Mol. Wt. (kg/kmol) / 1000 (m^3/10^3 m^3)

= 0.14598 Input this factor to the table above for C7+

GEF = Total (Pseudo 10^3 m^3 Gas / m^3 Liquid)

= 0.2247 **(10^3 m^3 Gas / m^3 Liquid)**

A6.2 Gas Equivalent Factor by Mole Fraction Calculation

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 (m^3/10^3 m^3)

Condensate Stream : ____________________

Component	Mol. Fraction Liquid Analysis		10^3 m^3/kmol @ 101.325 kPa & 15°C		Pseudo 10^3 m^3/kmol
N2		x	0.03475	=	
CO2		x	0.05359	=	
H2S		x	0.04263	=	
C1		x	0.05348	=	
C2		x	0.08399	=	
C3		x	0.08686	=	
IC4		x	0.10322	=	
NC4		x	0.09950	=	
IC5		x	0.11552	=	
NC5		x	0.11433	=	
C6		x	0.12980	=	
C7		x	0.14565	=	
C8		x	0.16163	=	
C9		x	0.17774	=	
C10		x	0.19391	=	
				Total =	

Note:

Properties of C5+, C6+, or C7+ Sample @ 15°C:

AD =

Mol. Wt. =

For C5+, C6+, or C7+ Sample:

10^3 m^3/kmol = Mol. Wt. / AD

=

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 (m^3/10^3 m^3)

= **(10^3 m^3 Gas / m^3 Liquid)**

Example 2

Gas Equivalent Factor by Mole Fraction Calculation

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 ($\text{m}^3/10^3\ \text{m}^3$)

Condensate Stream : ______________________________

Component	Mol. Fraction Liquid Analysis		m^3/kmol @ 101.325 kPa & 15°C		Pseudo m^3/kmol
N2	0.0019	x	0.03475	=	0.0001
CO2	0.0158	x	0.05359	=	0.0008
H2S	0	x	0.04263	=	0
C1	0.1617	x	0.05348	=	0.0086
C2	0.1462	x	0.08399	=	0.0123
C3	0.1533	x	0.08686	=	0.0133
IC4	0.0398	x	0.10322	=	0.0041
NC4	0.0935	x	0.09950	=	0.0093
IC5	0.0436	x	0.11552	=	0.0050
NC5	0.0493	x	0.11433	=	0.0056
C6	0.0614	x	0.12980	=	0.0080
C7+	0.2335	x	0.16198	=	0.0378
		x		=	
		x		=	
	1.0000			**Total =**	0.1049

Note:

Properties of C7+ sample @ 15 °C:

AD = 785.29

Mol. Wt. = 127.2

For C7+ Fraction:

m^3/kmol = Mol. Wt. / AD

= 0.16198 Input this factor to the table above for C7+

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 ($\text{m}^3/10^3\ \text{m}^3$)

= **0.2254** **($10^3\ \text{m}^3$ Gas / m^3 Liquid)**

A6.3 Gas Equivalent Factor by Mass Fraction Calculation

Step 1. Calculate Pseudo Volume (L) = Mass Fraction / Liquid Density x 1000 L/m^3

Step 2. Calculate Volume Fraction = Component Pseudo Volume / Total Pseudo Volume

Step 3. Calculate Component Pseudo GEF = Volume Fraction x (10^3 m^3 Gas / m^3 Liquid)

Condensate Stream : ______________________________

					Step 1	**Step 2**				**Step 3**
Component	**Mass Fraction Liquid Analysis**		**Liquid Density (kg/m^3)**		**Pseudo Volume (L)**	**Volume Fraction**		**10^3 m^3 Gas / m^3 Liquid @ 101.325 kPa & 15°C**		**Pseudo 10^3 m^3 Gas / m^3 Liquid**
N2		/	806.10	=			x	0.68040	=	
CO2		/	821.22	=			x	0.44120	=	
H2S		/	799.40	=			x	0.55460	=	
C1		/	300.00	=			x	0.44217	=	
C2		/	358.00	=			x	0.28151	=	
C3		/	507.67	=			x	0.27222	=	
IC4		/	563.07	=			x	0.22906	=	
NC4		/	584.14	=			x	0.23763	=	
IC5		/	624.54	=			x	0.20468	=	
NC5		/	631.05	=			x	0.20681	=	
C6		/	663.89	=			x	0.18216	=	
C7		/	687.98	=			x	0.16234	=	
C8		/	706.73	=			x	0.14629	=	
C9		/	721.59	=			x	0.13303	=	
C10		/	733.76	=			x	0.12194	=	
									Total =	

Note: For C5+, C6+, or C7+ Sample:

Mol. Wt. = ☐

AD = ☐

10^3 m^3 Gas / m^3 Liquid = 23.645 x AD / Mol. Wt. / 1000 m^3/10^3 m^3

= ☐

GEF = Total (Pseudo 10^3 m^3 Gas / m^3 Liquid)

= ☐ **(10^3 m^3 Gas / m^3 Liquid)**

Example 3

Gas Equivalent Factor by Mass Fraction Calculation

Step 1. Calculate Pseudo Volume (L) = Mass Fraction / Liquid Density x 1000 L/m^3

Step 2. Calculate Volume Fraction based on total pseudo volume

Step 3. Calculate Component Pseudo GEF = Volume Fraction x (10^{3}m^3 Gas / m^3 Liquid)

Condensate Stream : ______________________________

					Step 1	**Step 2**				**Step 3**
Component	**Mass Fraction Liquid Analysis**		**Liquid Density (kg/m^3)**		**Pseudo Volume (L)**	**Volume Fraction**		**10^3 m^3 Gas / m^3 Liquid @ 101.325 kPa & 15°C**		**Pseudo 10^3 m^3 Gas / m^3 Liquid**
N2	0.0008	/	806.10	=	0.0010	0.0006	x	0.68040	=	0.0004
CO2	0.0109	/	821.22	=	0.0133	0.0081	x	0.44120	=	0.0036
H2S	0	/	799.40	=			x	0.55460	=	
C1	0.0405	/	300.00	=	0.1350	0.0822	x	0.44217	=	0.0363
C2	0.0687	/	358.00	=	0.1919	0.1168	x	0.28148	=	0.0329
C3	0.1056	/	507.67	=	0.2080	0.1266	x	0.27221	=	0.0345
IC4	0.0362	/	563.07	=	0.0643	0.0391	x	0.22906	=	0.0090
NC4	0.0849	/	584.14	=	0.1453	0.0885	x	0.23763	=	0.0210
IC5	0.0492	/	624.54	=	0.0788	0.0480	x	0.20468	=	0.0098
NC5	0.0556	/	631.05	=	0.0881	0.0536	x	0.20681	=	0.0111
C6	0.0835	/	663.89	=	0.1258	0.0766	x	0.18216	=	0.0140
C7+	0.4641	/	785.29	=	0.5910	0.3598	x	0.14598	=	0.0525
	1.0000				1.6425	1.0000			**Total =**	0.2251

Note: For C7+ Sample:

Mol. Wt. = 127.2

AD of C7+ liquid = 785.29 (kg/m^3)

10^3 m^3 Gas / m^3 Liquid = 23.645 x AD / Mol. Wt. x 999.10 / 1000 (m^3/10^3 m^3)

= 0.14598 Input this factor to the table above for C7+

GEF = Total (Pseudo 10^3 m^3 Gas / m^3 Liquid)

= **0.2251** **(10^3 m^3 Gas / m^3 Liquid)**

Appendix 7 Calculated Compositional Analysis Examples

Calculated Well Stream Compositional Analysis Example

Step 1: Collect volumetric and compositional data for both gas and liquid phases.

Gas	
Gas Volume (10^3 m^3)	10000.0
Composition	*Mole %*
N2	1.00
CO2	2.00
H2S	2.40
C1	80.00
C2	8.00
C3	3.00
IC4	1.00
NC4	1.50
IC5	0.20
NC5	0.50
C6	0.30
C7+	0.10
	100.00

Liquid	
Liquid Volume (m^3)	200.0
Composition	*Mole %*
N2	0.00
CO2	1.00
H2S	2.00
C1	3.00
C2	4.00
C3	7.00
IC4	10.00
NC4	15.00
IC5	7.00
NC5	11.00
C6	10.00
C7+	30.00
	100.00

Step 2: Convert the condensate liquid volume to a GEV.

A) Convert liquid volume to equivalent gas volume using the condensate gas equivalent factor.

Equation 1: *GEV = Volume of condensate (m^3) x GEF (m^3 gas per m^3 liquid)*

GEV = 200 (m^3) x 220.12 (m^3 gas per m^3 liquid) ÷ 1000 (10^3 m^3/m^3) = 44.024 10^3 m^3

If the gas equivalent factor is not included with the condensate analysis report, it can be calculated.

Equation 2: *GEF = Absolute Density of Condensate (kg/m^3 @ 15°C) / Molecular weight of the condensate (grams/mole)*

B) Convert the compositional fractions to equivalent gas volumes on a component basis.

Equation 3: *Component gas volume (10^3 m^3) = [Component mole percent] x [GEV]*

Example: n-pentane equivalent volume:
Volume of condensate = 200 m^3
Gas Equivalent Factor = 220.12
Equivalent n-pentane (NC5) gas volume = [11.0%] x [44.024 10^3 m^3] = 4843 m^3

Liquid	
Liquid Volume (m^3)	200.0
Composition	*Mole %*
N2	0.00
CO2	1.00
H2S	2.00
C1	3.00
C2	4.00
C3	7.00
IC4	10.00
NC4	15.00
IC5	7.00
NC5	11.00
C6	10.00
C7+	30.00
	100.00

A

B

Liquid	
Gas Equivalent Volume (10^3 m^3)	44.024
Composition	*10^3 m^3 gas*
N2	0.00
CO2	0.44
H2S	0.88
C1	1.32
C2	1.76
C3	3.08
IC4	4.40
NC4	6.60
IC5	3.08
NC5	4.84
C6	4.40
C7+	13.21
	44.02

Step 3:
Add the gas volumes and liquid gas equivalent volumes and normalize to mole fraction 1 or 100%

Gas	
Gas Volume ($10^3 m^3$)	10000.0
Composition	*$10^3 m^3$ gas*
N2	100.0
CO2	200.0
H2S	240.0
C1	8000.0
C2	800.0
C3	300.0
IC4	100.0
NC4	150.0
IC5	20.0
NC5	50.0
C6	30.0
C7+	10.0
	10000.0

+

Liquid	
Gas Equivalent Volume ($10^3 m^3$)	44.0
Composition	*$10^3 m^3$ gas*
N2	0.00
CO2	0.44
H2S	0.88
C1	1.32
C2	1.76
C3	3.08
IC4	4.40
NC4	6.60
IC5	3.08
NC5	4.84
C6	4.40
C7+	13.21
	44.0

=

Recombined Volume	
Gas Equivalent Volume ($10^3 m^3$)	10044.0
Composition	*$10^3 m^3$ gas*
N2	100.0
CO2	200.4
H2S	240.9
C1	8001.3
C2	801.8
C3	303.1
IC4	104.4
NC4	156.6
IC5	23.1
NC5	54.8
C6	34.4
C7+	23.2
	10044.0

Recombined Composition	
Gas Equivalent Volume ($10^3 m^3$)	10044.0
Composition	*Mole %*
N2	1.00
CO2	2.00
H2S	2.40
C1	79.66
C2	7.98
C3	3.02
IC4	1.04
NC4	1.56
IC5	0.23
NC5	0.55
C6	0.34
C7+	0.23
	100.00

Calculated Group Compositional Analysis Example

Step 1:
Collect volumetric and compositional data for both gas and liquid phases for all streams. This information is required for all wells.

Step 2:
Mathematically recombine the fluid based on volumetric and compositional data collected in Step 1 for each stream.

Step 3:
Add the recombined fluid volumes on a component basis and normalize to 100%.

Stream 1: Gas	
Gas Volume ($10^3 m^3$)	10000
Composition	*Mole %*
N2	1.14
CO2	0.16
H2S	0.00
C1	85.31
C2	6.44
C3	3.77
IC4	0.63
NC4	1.32
IC5	0.33
NC5	0.41
C6	0.26
C7+	0.23
	100.00

Liquid	
Gas Equivalent Volume ($10^3 m^3$)	800
Composition	*Mole %*
N2	0.12
CO2	0.08
H2S	0.00
C1	22.02
C2	6.14
C3	8.56
IC4	2.62
NC4	7.11
IC5	3.66
NC5	5.73
C6	9.73
C7+	34.23
	100.00

Recombined Fluid	
Gas Equivalent Volume ($10^3 m^3$)	10800
Composition	*Mole %*
N2	1.06
CO2	0.15
H2S	0.00
C1	80.62
C2	6.42
C3	4.12
IC4	0.78
NC4	1.75
IC5	0.58
NC5	0.80
C6	0.96
C7+	2.75
	100.00

Stream 2: Gas	
Gas Volume ($10^3 m^3$)	15000
Composition	*Mole %*
N2	1.00
CO2	2.00
H2S	2.40
C1	80.00
C2	8.00
C3	3.00
IC4	1.00
NC4	1.50
IC5	0.20
NC5	0.50
C6	0.30
C7+	0.10
	100.00

Liquid	
Gas Equivalent Volume ($10^3 m^3$)	200
Composition	*Mole %*
N2	0.00
CO2	1.00
H2S	2.00
C1	3.00
C2	4.00
C3	7.00
IC4	10.00
NC4	15.00
IC5	7.00
NC5	11.00
C6	10.00
C7+	30.00
	100.00

Recombined Fluid	
Gas Equivalent Volume ($10^3 m^3$)	15200
Composition	*Mole %*
N2	0.99
CO2	1.99
H2S	2.39
C1	78.99
C2	7.95
C3	3.05
IC4	1.12
NC4	1.68
IC5	0.29
NC5	0.64
C6	0.43
C7+	0.49
	100.00

Total Recombined Fluid	
Gas Equivalent Volume ($10^3 m^3$)	36000
Composition	*Mole %*
N2	0.76
CO2	1.44
H2S	1.01
C1	82.37
C2	6.95
C3	2.94
IC4	0.79
NC4	1.37
IC5	0.32
NC5	0.54
C6	0.47
C7+	1.04
	100.00

Stream 3: Gas	
Gas Volume ($10^3 m^3$)	10000
Composition	*Mole %*
N2	0.10
CO2	2.00
H2S	0.00
C1	89.40
C2	6.00
C3	1.50
IC4	0.30
NC4	0.50
IC5	0.08
NC5	0.10
C6	0.01
C7+	0.01
	100.00

Liquid	
Gas Equivalent Volume ($10^3 m^3$)	0
Composition	*Mole %*
N2	0.00
CO2	0.00
H2S	0.00
C1	0.00
C2	0.00
C3	0.00
IC4	0.00
NC4	0.00
IC5	0.00
NC5	0.00
C6	0.00
C7+	0.00
	0.00

Recombined Fluid	
Gas Equivalent Volume ($10^3 m^3$)	10000
Composition	*Mole %*
N2	0.10
CO2	2.00
H2S	0.00
C1	89.40
C2	6.00
C3	1.50
IC4	0.30
NC4	0.50
IC5	0.08
NC5	0.10
C6	0.01
C7+	0.01
	100.00

Calculated Single Compositional Analysis (from Two Samples)

Step 1: Collect spot samples and record the metered volumes associated with each sample.

Step 2: Calculate individual component volumes by multiplying the individual component mole fractions or percentage values by the associated metered volumes.

Example: Gas Sample #1, Calculation of methane volume
Total Volume = 10000 $10^3 m^3$
Methane = 80.00 mole %
Methane Volume = 10000.0 $10^3 m^3$ X 0.8000 = 8000.0 $10^3 m^3$

Step 3: Normalization: Individual component volumes are summed. The individual component volumes are then be divided into the total to create a normalized (calculated) compositional value.

Example: Ethane (C2), Calculation of Mole %
Gas Sample #1, C2 volume: 800 $10^3 m^3$
Gas Sample #2, C2 volume: 560 $10^3 m^3$
Combined, C2 volume: 1360 $10^3 m^3$
Total gas volume: 18000 $10^3 m^3$
Calculated C2 concentration = 1360.0 $10^3 m^3$ / 18000 $10^3 m^3$ = 7.56 mole %

Gas Sample #1		
Gas Volume ($10^3 m^3$) = 10000.0		
Component	*Mole %*	*$10^3 m^3$ gas*
N2	1.00	100.0
CO2	2.00	200.0
H2S	2.40	240.0
C1	80.00	8000.0
C2	8.00	800.0
C3	3.00	300.0
IC4	1.00	100.0
NC4	1.50	150.0
IC5	0.20	20.0
NC5	0.50	50.0
C6	0.30	30.0
C7+	0.10	10.0
	100.00	10000.0

+

Gas Sample #2		
Gas Volume ($10^3 m^3$) = 8000.0		
Component	*Mole %*	*$10^3 m^3$ gas*
N2	0.60	48.0
CO2	2.00	160.0
H2S	1.50	120.0
C1	83.00	6640.0
C2	7.00	560.0
C3	2.50	200.0
IC4	1.00	80.0
NC4	1.40	112.0
IC5	0.18	14.4
NC5	0.45	36.0
C6	0.28	22.4
C7+	0.09	7.2
	100.00	8000.0

=

Calculated Single Compositional Analysis		
Gas Volume ($10^3 m^3$) = 18000.0		
Component	***Calculated Mole %***	*$10^3 m^3$ gas*
N2	**0.82**	148.0
CO2	**2.00**	360.0
H2S	**2.00**	360.0
C1	**81.33**	14640.0
C2	**7.56**	1360.0
C3	**2.78**	500.0
IC4	**1.00**	180.0
NC4	**1.46**	262.0
IC5	**0.19**	34.4
NC5	**0.48**	86.0
C6	**0.29**	52.4
C7+	**0.10**	17.2
	100.00	18000.0

Appendix 8 Blending Shrinkage Calculation Example

	API MPMS Chapter 12.3, Section 5.3, Eq. 3

% Shrinkage = 26900 * C * (100 - C) ^ 0.819 * (1/dL - 1/dH) ^ 2.28

C = Diluent Volume / (Bitumen Volume + Diluent Volume)

dL = Weighted Average Diluent Density

dH = Weighted Average Crude Density

Inputs	Volume (m^3)	Density (kg/m^3)
Light Component	800.0	700.0
Heavy Component	2300.0	963.0

	Volume %
Light Component % in Blend	25.81%
Heavy Component % in Blend	74.19%

C = 25.81%

1/dL = 0.00143

1/dH = 0.00104

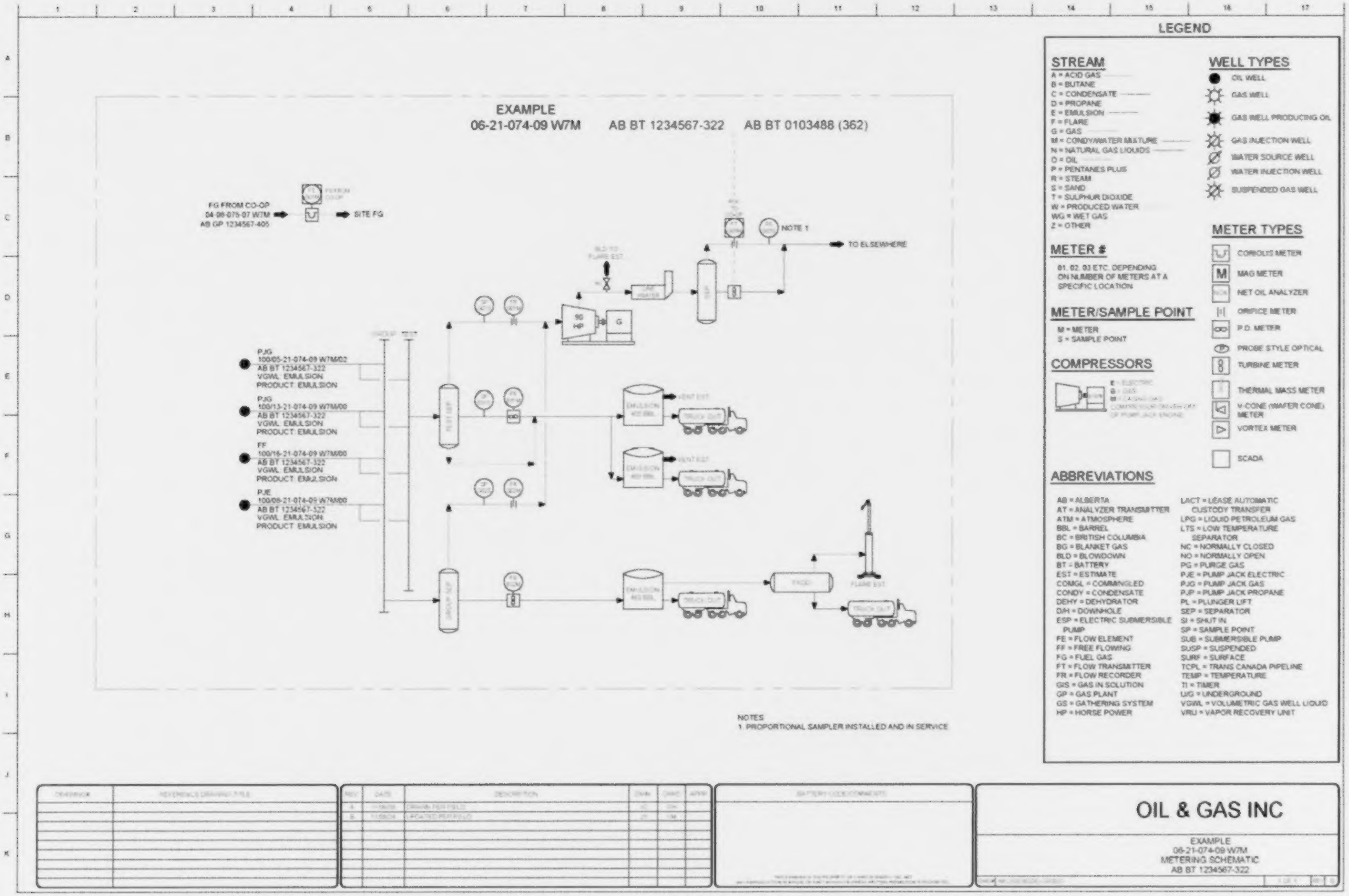
% Shrinkage = 0.3993%

For blending 2300 m^3 of 963 kg/m^3 oil and 800 m^3 of 700 kg/m^3 diluent:

Shrinkage volume = 0.3993% x (800 + 2300) = 12.38 m^3

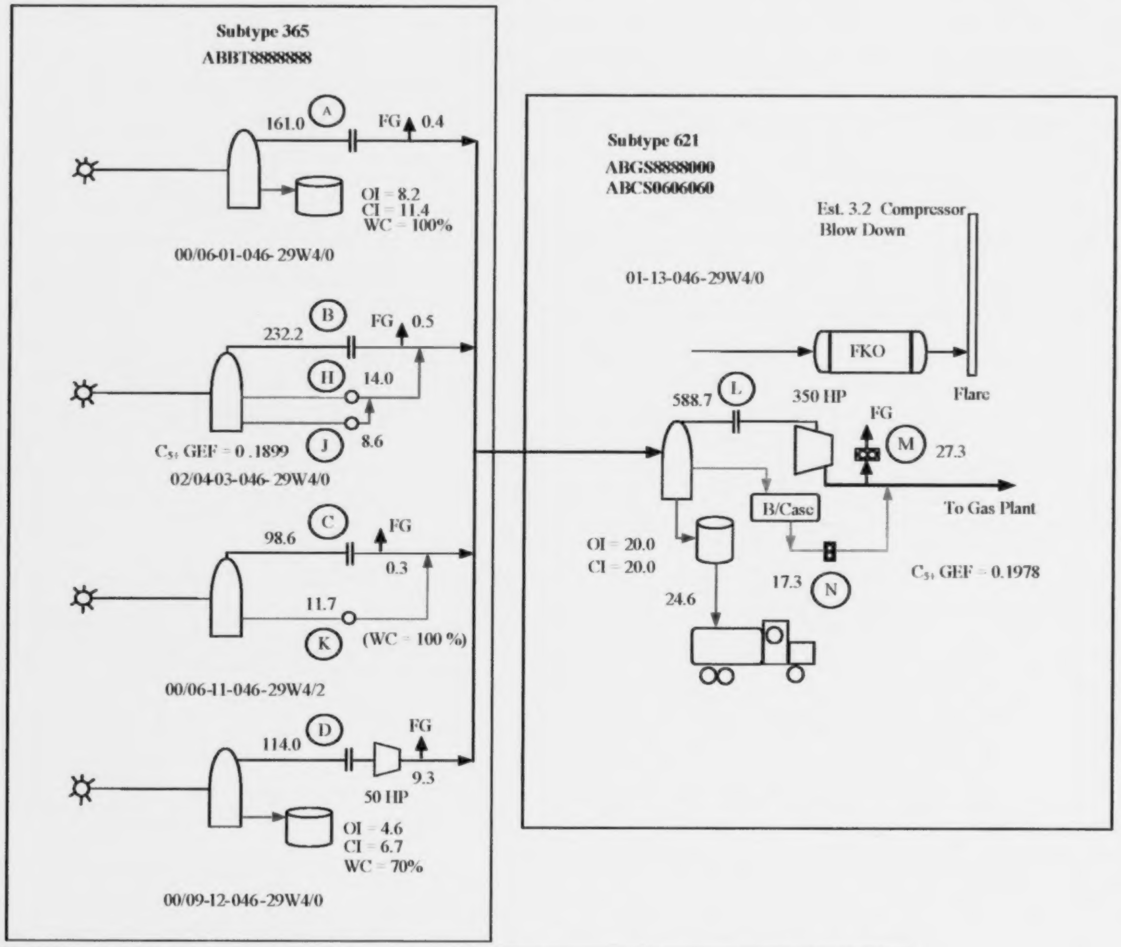
Appendix 9 Schematic Example

The example on the following page is for information purposes only. An operator may use other symbols, letters, or words as long as it is clear in the legend or in the schematic what they stand for.


EXAMPLE
06-21-074-09 W7M
AB BT 1234567-322
AB BT 0103488 (362)
FG FROM CO-OP
04-08-075-07 W7M
AB GP 1234567-405
SITE FG
NOTE 1
TO ELSEWHERE
90
HP
G
GROUP
TEST
PJG
100/05-21-074-09 W7M/02
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
PJG
100/13-21-074-09 W7M/00
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
FF
100/16-21-074-09 W7M/00
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
PJE
100/08-21-074-09 W7M/00
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
TEST SEP
GROUP SEP
EMULSION
VENT EST
TRUCK OUT
FLARE EST
NOTES
1. PROPORTIONAL SAMPLER INSTALLED AND IN SERVICE
LEGEND
STREAM
A = ACID GAS
B = BUTANE
C = CONDENSATE
D = PROPANE
E = EMULSION
F = FLARE
G = GAS
M = CONDY/WATER MIXTURE
N = NATURAL GAS LIQUIDS
O = OIL
P = PENTANES PLUS
R = STEAM
S = SAND
T = SULPHUR DIOXIDE
W = PRODUCED WATER
WG = WET GAS
Z = OTHER
METER #
01, 02, 03 ETC. DEPENDING ON NUMBER OF METERS AT A SPECIFIC LOCATION
METER/SAMPLE POINT
M = METER
S = SAMPLE POINT
COMPRESSORS
E = ELECTRIC
G = GAS
WELL TYPES
OIL WELL
GAS WELL
GAS WELL PRODUCING OIL
GAS INJECTION WELL
WATER SOURCE WELL
WATER INJECTION WELL
SUSPENDED GAS WELL
METER TYPES
CORIOLIS METER
MAG METER
NET OIL ANALYZER
ORIFICE METER
P.D. METER
PROBE STYLE OPTICAL
TURBINE METER
THERMAL MASS METER
V-CONE (WAFER CONE) METER
VORTEX METER
SCADA
ABBREVIATIONS
AB = ALBERTA
AT = ANALYZER TRANSMITTER
ATM = ATMOSPHERE
BBL = BARREL
BC = BRITISH COLUMBIA
BG = BLANKET GAS
BLD = BLOWDOWN
BT = BATTERY
EST = ESTIMATE
COMGL = COMMINGLED
CONDY = CONDENSATE
DEHY = DEHYDRATOR
D/H = DOWNHOLE
ESP = ELECTRIC SUBMERSIBLE PUMP
FE = FLOW ELEMENT
FF = FREE FLOWING
FG = FUEL GAS
FT = FLOW TRANSMITTER
FR = FLOW RECORDER
GIS = GAS IN SOLUTION
GP = GAS PLANT
GS = GATHERING SYSTEM
HP = HORSE POWER
LACT = LEASE AUTOMATIC CUSTODY TRANSFER
LPG = LIQUID PETROLEUM GAS
LTS = LOW TEMPERATURE SEPARATOR
NC = NORMALLY CLOSED
NO = NORMALLY OPEN
PG = PURGE GAS
PJE = PUMP JACK ELECTRIC
PJG = PUMP JACK GAS
PJP = PUMP JACK PROPANE
PL = PLUNGER LIFT
SEP = SEPARATOR
SI = SHUT IN
SP = SAMPLE POINT
SUB = SUBMERSIBLE PUMP
SUSP = SUSPENDED
SURF = SURFACE
TCPL = TRANS CANADA PIPELINE
TEMP = TEMPERATURE
TI = TIMER
U/G = UNDERGROUND
VGWL = VOLUMETRIC GAS WELL LIQUID
VRU = VAPOR RECOVERY UNIT
OIL & GAS INC
EXAMPLE
06-21-074-09 W7M
METERING SCHEMATIC
AB BT 1234567-322

Appendix 10 Gas Group Delineation

Case 1[1, 2]


Subtype 365
ABBT8888888
161.0
A
FG 0.4
OI = 8.2
CI = 11.4
WC = 100%
00/06-01-046-29W4/0
B
232.2
FG 0.5
H
14.0
J
8.6
C_{5+} GEF = 0.1899
02/04-03-046-29W4/0
C
98.6
FG
0.3
11.7
K
(WC = 100 %)
00/06-11-046-29W4/2
D
114.0
FG
9.3
50 HP
OI = 4.6
CI = 6.7
WC = 70%
00/09-12-046-29W4/0
Subtype 621
ABGS8888000
ABCS0606060
Est. 3.2 Compressor Blow Down
01-13-046-29W4/0
FKO
Flare
588.7
L
350 HP
FG
M
27.3
To Gas Plant
B/Case
OI = 20.0
CI = 20.0
24.6
17.3
N
C_{5+} GEF = 0.1978

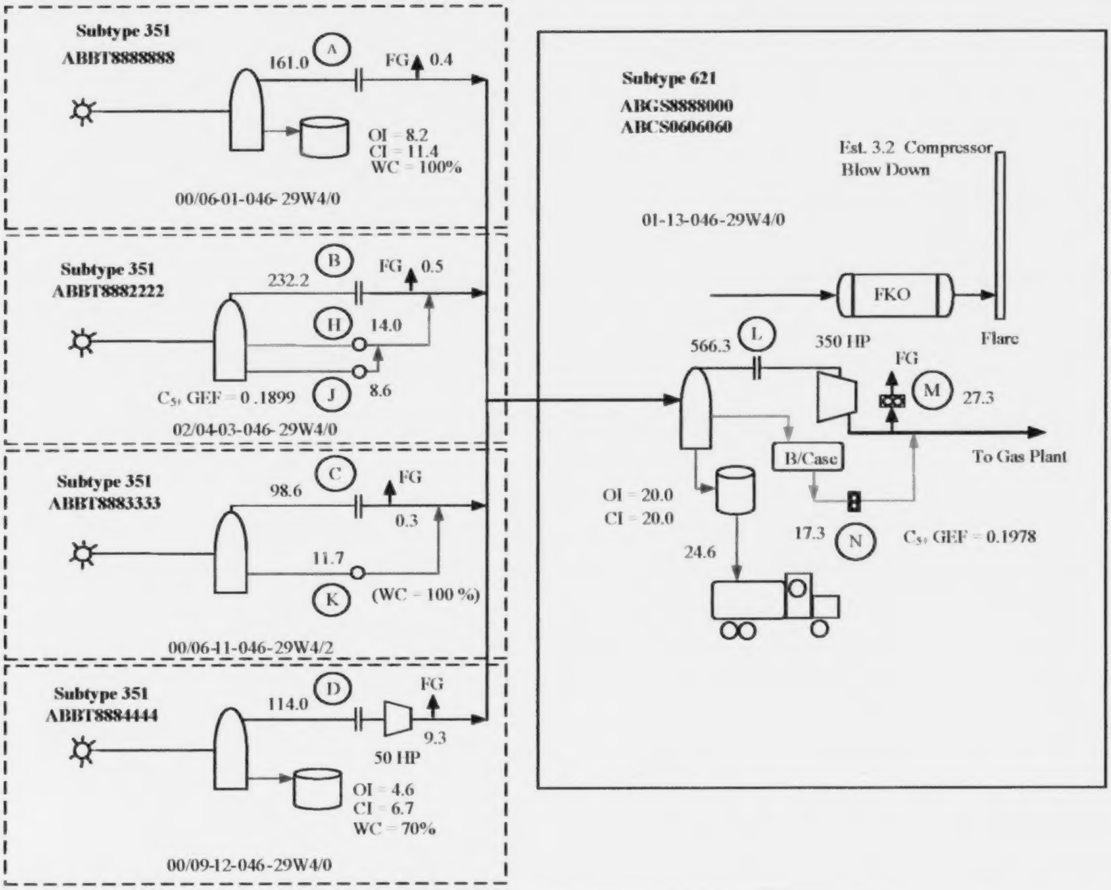
ABBT8888888 Gas Production = 161.0 + 232.2 + (0.1899 x 14.0) + 98.6 + 114.0 = 608.5
ABBT8888888 Gas Delivered = 608.5 – (0.4 + 0.5 + 0.3 + 9.3) = 598.0
ABBT8888888 Water Production = 3.2 + 8.6 + 11.7 + [(6.7 – 4.6) x 0.7] = 25.0
ABBT8888888 Oil Production = [(6.7 – 4.6) x 0.3] = 0.6
ABGS8888000 Receipts = 598.0
ABGS8888000 Gas Delivered = 588.7 – 27.3 + (0.1978 x 17.3) – 3.2 = 561.6
ABGS8888000 MD = 598.0 – 588.7 – (0.1978 x 17.3) = 5.9 (1.0%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

---

[1] All wells sweet

[2] All volumes monthly

Case 2[1, 2]


Subtype 351
ABBT8888888
161.0
A
FG 0.4
OI = 8.2
CI = 11.4
WC = 100%
00/06-01-046-29W4/0
Subtype 351
ABBT8882222
232.2
B
FG 0.5
H
14.0
J
8.6
C5, GEF = 0.1899
02/04-03-046-29W4/0
Subtype 351
ABBT8883333
98.6
C
FG
0.3
11.7
K
(WC = 100 %)
00/06-11-046-29W4/2
Subtype 351
ABBT8884444
114.0
D
FG
9.3
50 HP
OI = 4.6
CI = 6.7
WC = 70%
00/09-12-046-29W4/0
Subtype 621
ABGS8888000
ABCS0606060
Est. 3.2 Compressor Blow Down
01-13-046-29W4/0
FKO
Flare
566.3
L
350 HP
FG
M
27.3
To Gas Plant
B/Case
OI = 20.0
CI = 20.0
24.6
17.3
N
C5, GEF = 0.1978

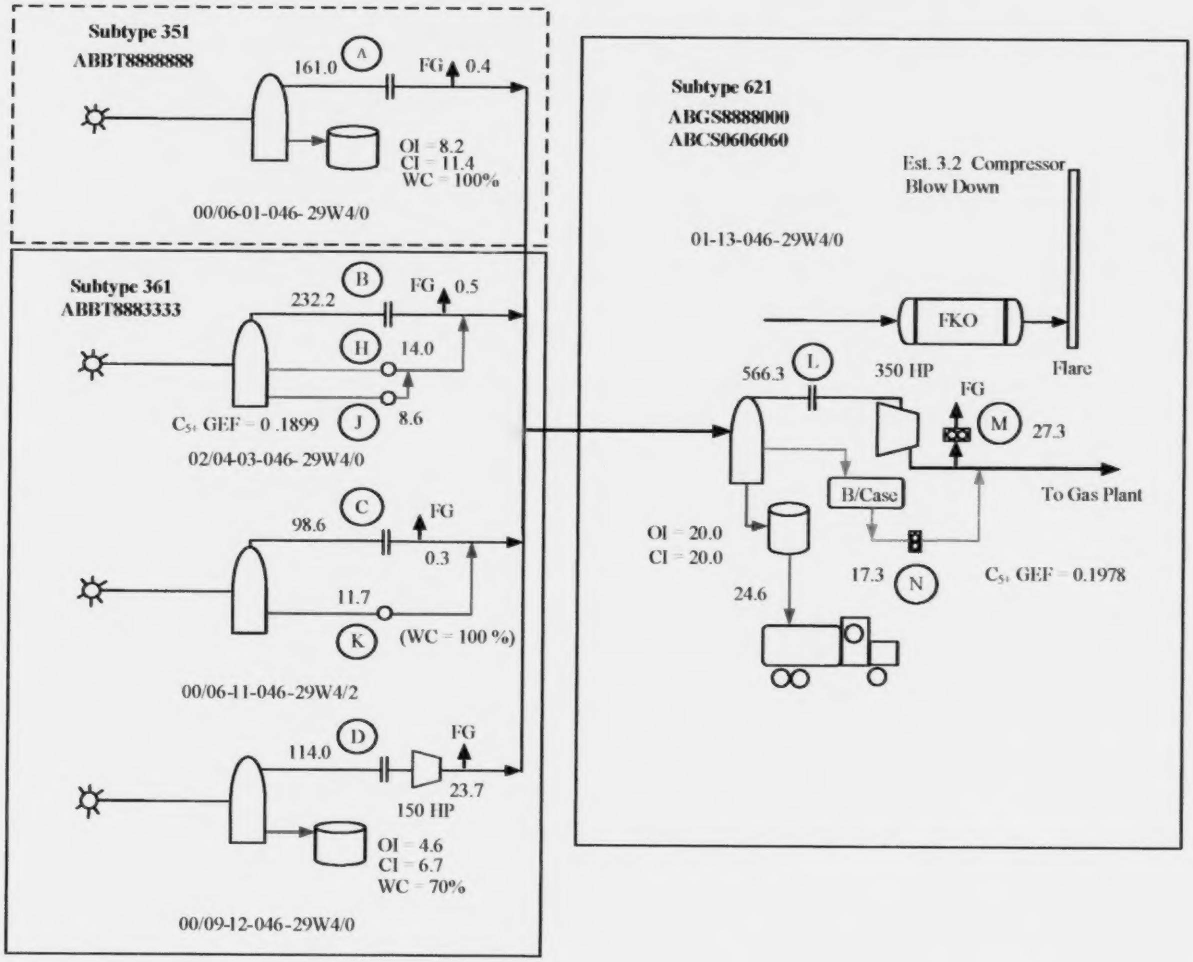
ABBT8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.6
ABBT8888888 Water Production = 3.2
ABBT8882222 Gas Production = 232.2 + (14 x 0.1899) = 234.9; Delivered = 234.9 – 0.5 = 234.4
ABBT8882222 Water Production = 8.6
ABBT8883333 Gas Production = 98.6; Delivered = 98.6 – 0.3 = 98.3
ABBT8883333 Water Production = 11.7
ABBT8884444 Gas Production = 114.0; Delivered = 114 – 23.7 = 90.3
ABBT8884444 Water Production = (6.7 – 4.6) x 0.7 = 1.5
ABBT8884444 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABGS8888000 Gas Receipts = 160.6 + 234.4 + 98.3 + 90.3 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

---

[1] All wells sweet

[2] All volumes monthly

Case 3[1, 2]


Subtype 351
ABBT8888888
161.0
A
FG 0.4
OI = 8.2
CI = 11.4
WC = 100%
00/06-01-046-29W4/0
Subtype 361
ABBT8883333
232.2
B
FG 0.5
H
14.0
C5+ GEF = 0 .1899
J
8.6
02/04-03-046-29W4/0
98.6
C
FG
0.3
11.7
K
(WC = 100 %)
00/06-11-046-29W4/2
114.0
D
FG
23.7
150 HP
OI = 4.6
CI = 6.7
WC = 70%
00/09-12-046-29W4/0
Subtype 621
ABGS8888000
ABCS0606060
Est. 3.2 Compressor
Blow Down
01-13-046-29W4/0
FKO
Flare
566.3
L
350 HP
FG
M
27.3
To Gas Plant
B/Case
OI = 20.0
CI = 20.0
24.6
17.3
N
C5+ GEF = 0.1978

ABBT8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.7

ABBT8888888 Water Production = 3.2

ABBT8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 + 114 = 447.5; Delivered = 447.5 – 24.5 = 423.0

ABBT8883333 Water Production = 8.6 + 11.7 + [(6.7 – 4.6) x 0.7] = 21.8

ABBT8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6

ABGS8888000 Receipts = 423.0 + 160.6 = 583.6

ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2

ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)

ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6

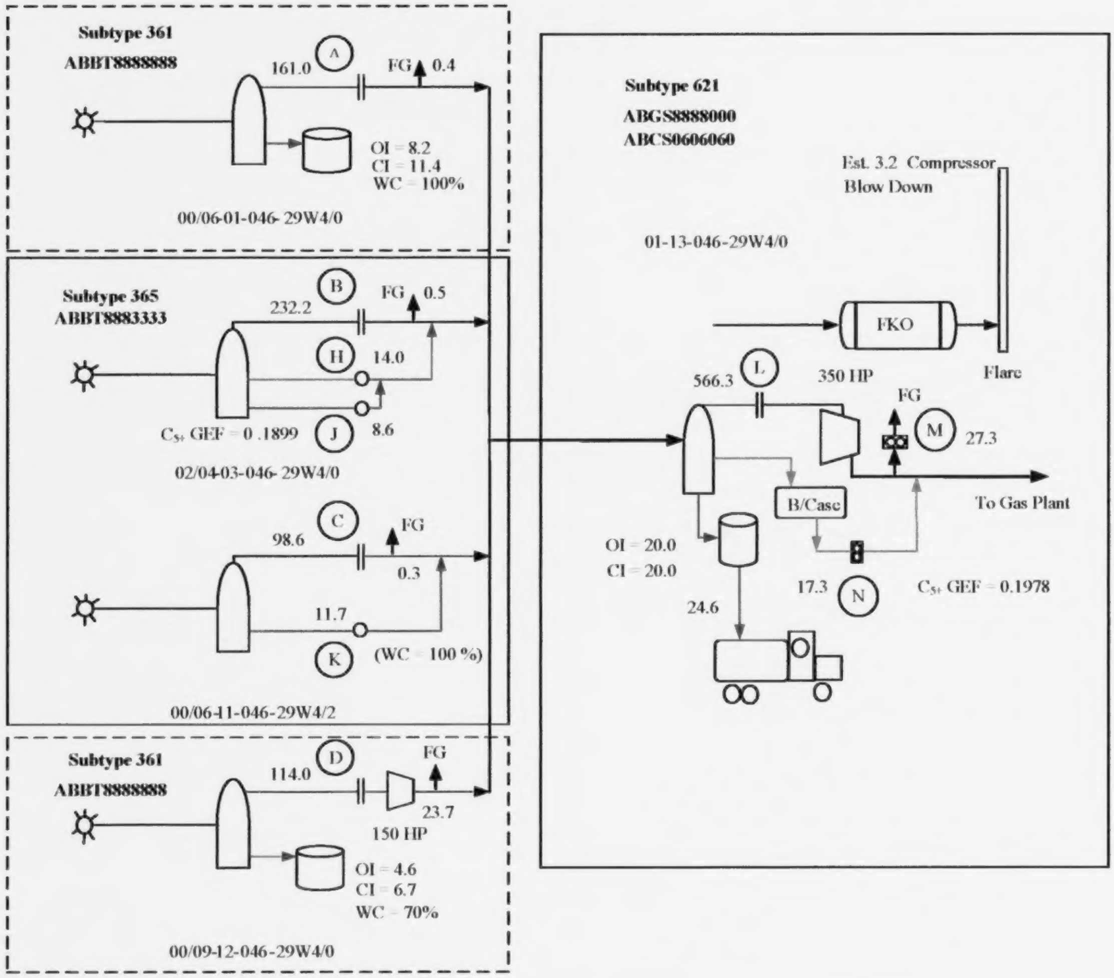
ABWC Water Receipt = 24.6 – 20.3 = 4.3

---

[1] All wells sweet

[2] All volumes monthly

Case 4[1, 2]

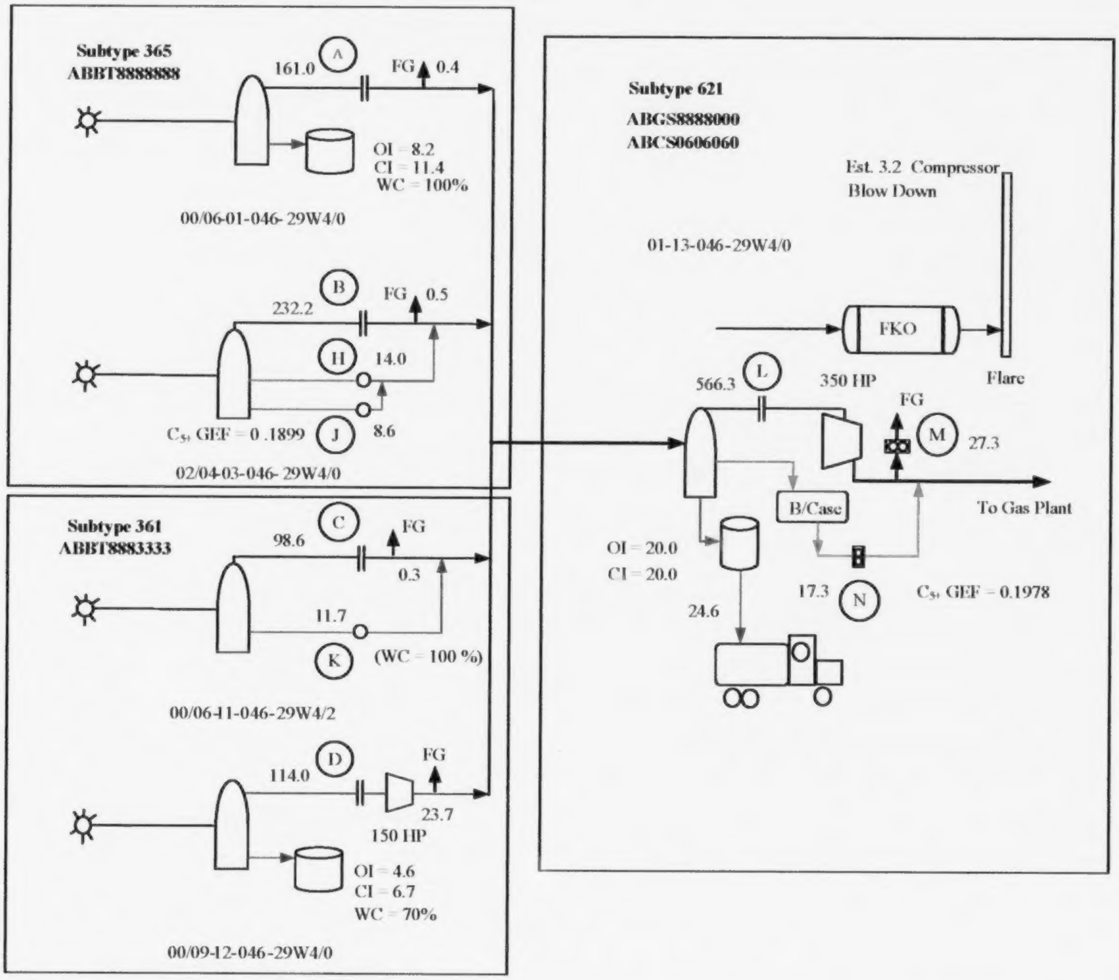

Subtype 361
ABBT8888888
161.0
A
FG
0.4
OI = 8.2
CI = 11.4
WC = 100%
00/06-01-046-29W4/0
Subtype 365
ABBT8883333
B
232.2
FG
0.5
H
14.0
C5+ GEF = 0.1899
J
8.6
02/04-03-046-29W4/0
C
98.6
FG
0.3
11.7
K
(WC = 100 %)
00/06-11-046-29W4/2
Subtype 361
ABBT8888888
D
114.0
FG
23.7
150 HP
OI = 4.6
CI = 6.7
WC = 70%
00/09-12-046-29W4/0
Subtype 621
ABGS8888000
ABCS0606060
Est. 3.2 Compressor Blow Down
01-13-046-29W4/0
FKO
Flare
566.3
L
350 HP
FG
M
27.3
To Gas Plant
B/Case
OI = 20.0
CI = 20.0
17.3
N
C5+ GEF = 0.1978
24.6

ABBT8888888 Gas Production = 161.0 + 114.0 = 275.0; Delivered = 275 – 0.4 – 23.7 = 250.9
ABBT8888888 Water Production = (11.4 – 8.2) + [(6.7 – 4.6) x 0.7] = 4.7
ABBT8888888 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABBT8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 = 333.5; Delivered = 333.5 – 0.5 – 0.3 = 332.7
ABBT8883333 Water Production = 8.6 + 11.7 = 20.3
ABGS8888000 Receipts = 250.9 + 332.7 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

---

[1] All wells sweet
[2] All volumes monthly

Case 5[1, 2]


Subtype 365
ABBT8888888
161.0
A
FG 0.4
OI = 8.2
CI = 11.4
WC = 100%
00/06-01-046-29W4/0
B
FG 0.5
232.2
H
14.0
C5+ GEF = 0 .1899
J
8.6
02/04-03-046-29W4/0
Subtype 361
ABBT8883333
C
FG
98.6
0.3
11.7
K
(WC = 100 %)
00/06-11-046-29W4/2
D
FG
114.0
23.7
150 HP
OI = 4.6
CI = 6.7
WC = 70%
00/09-12-046-29W4/0
Subtype 621
ABGS8888000
ABCS0606060
Est. 3.2 Compressor
Blow Down
01-13-046-29W4/0
FKO
566.3
L
350 HP
Flare
FG
M
27.3
To Gas Plant
B/Case
OI = 20.0
CI = 20.0
17.3
N
C5+ GEF = 0.1978
24.6

ABBT8888888 Gas Production = 161.0 + 232.2 + (14 x 0.1899) = 395.9; Delivered = 395.9 – 0.4 – 0.5 = 395.0
ABBT8888888 Water Production = (11.4 – 8.2) + 8.6 = 11.8
ABBT8883333 Gas Production = 98.6 + 114 = 212.6; Delivered = 212.6 – 24 = 188.6
ABBT8883333 Water Production = 11.7 + [(6.7 – 4.6) x 0.7] = 13.2
ABBT8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABGS8888000 Receipts = 395 + 188.6 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

---

[1] All wells sweet
[2] All volumes monthly